UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2004

o 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	**Registrants; States of Incorporation; Address and Telephone Number**	**I.R.S. Employer Identification Nos.**
1-3525	American Electric Power Company, Inc . (A New York Corporation)	13-4922640
0-18135	AEP Generating Company (An Ohio Corporation)	31-1033833
0-346	AEP Texas Central Company (A Texas Corporation)	74-0550600
0-340	AEP Texas North Company (A Texas Corporation)	75-0646790
1-3457	Appalachian Power Company (A Virginia Corporation)	54-0124790
1-2680	Columbus Southern Power Company (An Ohio Corporation)	31-4154203
1-3570	Indiana Michigan Power Company (An Indiana Corporation)	35-0410455
1-6858	Kentucky Power Company (A Kentucky Corporation)	61-0247775
1-6543	Ohio Power Company (An Ohio Corporation)	31-4271000
0-343	Public Service Company of Oklahoma (An Oklahoma Corporation)	73-0410895

1-3146	Southwestern Electric Power Company (A Delaware Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 716-1000	72-0323455

Indicate by check mark whether the registrants (1) have 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 registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes x . No. o

Indicate by check mark if disclosure of delinquent filers with respect to American Electric Power Company, Inc. pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrants 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. x

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company, Indiana Michigan Power Company or Ohio Power Company pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrants knowledge, in definitive proxy or information statements of Appalachian Power Company or Ohio Power Company incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes x No o

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are accelerated filers (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes o No x

AEP Generating Company, AEP Texas North Company, Columbus Southern Power Company, Kentucky Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

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

Registrant	**Title of each class**	**Name of each exchange on which registered**
AEP Generating Company	None	
AEP Texas Central Company	None	
AEP Texas North Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
	9.25% Equity Units	New York Stock Exchange
Appalachian Power Company	None	
Columbus Southern Power Company	None	
Indiana Michigan Power Company	6% Senior Notes, Series D, Due 2032	New York Stock Exchange
Kentucky Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

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

Registrant	**Title of each class**
AEP Generating Company	None
AEP Texas Central Company	4.00% Cumulative Preferred Stock, Non-Voting, $100 par value 4.20% Cumulative Preferred Stock, Non-Voting, $100 par value
AEP Texas North Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	4.125% Cumulative Preferred Stock, Non-Voting, $100 par value
Kentucky Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value 4.65% Cumulative Preferred Stock, Non-Voting, $100 par value 5.00% Cumulative Preferred Stock, Non-Voting, $100 par value

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants at December 31, 2004	**Number of shares of common stock outstanding of the registrants at December 31, 2004**
AEP Generating Company	None	1,000 ($1,000 par value)
AEP Texas Central Company	None	2,211,678 ($25 par value)
AEP Texas North Company	None	5,488,560 ($25 par value)
American Electric Power Company, Inc.	$13,593,768,974	395,858,153 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)

Public Service Company of Oklahoma	None	9,013,000
		($15 par value)
Southwestern Electric Power Company	None	7,536,640
		($18 par value)

Note On Market Value Of Common Equity Held By Non-Affiliates

American Electric Power Company, Inc. owns, directly or indirectly, all of the common stock of AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Documents Incorporated By Reference

Description	**Part of Form 10-K Into Which Document Is Incorporated**
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2004:	Part II
AEP Generating Company AEP Texas Central Company AEP Texas North Company American Electric Power Company, Inc. Appalachian Power Company Columbus Southern Power Company Indiana Michigan Power Company Kentucky Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	
Portions of Proxy Statement of American Electric Power Company, Inc. for 2005 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2004	Part III
Portions of Information Statements of the following companies for 2005 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2004: Appalachian Power Company Ohio Power Company	Part III

This combined Form 10-K is separately filed by AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEPs website, including AEPs Principles of Business Conduct (which also serves as a code of ethics applicable to Item 10 of this Form 10-K), certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. AEP makes available, free of charge on its website, copies of its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

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GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP
AEP	American Electric Power Company, Inc.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP
AEP Power Pool	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEPR	AEP Resources, Inc., a subsidiary of AEP
AEPSC or Service Corporation	American Electric Power Service Corporation, a service subsidiary of AEP
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEPs electric utility subsidiaries
AEP Utilities	AEP Utilities, Inc., subsidiary of AEP, formerly, Central and South West Corporation
AFUDC	Allowance for funds used during construction (the net cost of borrowed funds, and a reasonable rate of return on other funds, used for construction under regulatory accounting)
ALJ	Administrative law judge
APCo	Appalachian Power Company, an electric utility subsidiary of AEP
Btu	British thermal unit
Buckeye	Buckeye Power, Inc., an unaffiliated corporation
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
Cardinal Station	Generating facility co-owned by Buckeye and OPCo
Centrica	Centrica U.S. Holdings, Inc., and its affiliates collectively, unaffiliated companies
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility company
Cook Plant	The Donald C. Cook Nuclear Plant (2,143 MW), owned by I&M, and located near Bridgman, Michigan
CSPCo	Columbus Southern Power Company, a public utility subsidiary of AEP
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation
DOE	United States Department of Energy
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
Dow	The Dow Chemical Company, and its affiliates collectively, unaffiliated companies
East zone public utility subsidiaries	APCo, CSPCo, I&M, KPCo and OPCo
ECOM	Excess cost over market
EMF	Electric and Magnetic Fields
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
FPA	Federal Power Act
FUCO	Foreign utility company as defined under PUHCA
I&M	Indiana Michigan Power Company, a public utility subsidiary of AEP
I&M Power Agreement	Unit Power Agreement Between AEGCo and I&M, dated March 31, 1982
Interconnection Agreement	Agreement, dated July 6, 1951, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants
IURC	Indiana Utility Regulatory Commission
KPCo	Kentucky Power Company, a public utility subsidiary of AEP

KPSC	Kentucky Public Service Commission
LLWPA	Low-Level Waste Policy Act of 1980
LPSC	Louisiana Public Service Commission
MECPL	Mutual Energy CPL, L.P., a Texas REP and former AEP affiliate
MEWTU	Mutual Energy WTU, L.P., a Texas REP and former AEP affiliate
MISO	Midwest Independent Transmission System Operator
Moodys	Moodys Investors Service, Inc.
MW	Megawatt
NOx	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff, filed with FERC
OCC	Corporation Commission of the State of Oklahoma
Ohio Act	Ohio electric restructuring legislation
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 44.2% equity interest
PJM	PJM Interconnection, L.L.C.; a regional transmission organization
Pro Serv	AEP Pro Serv, Inc., a subsidiary of AEP
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PTB	Price to beat, as defined by the Texas Act
PUCO	The Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935, as amended
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Retail electricity provider
Rockport Plant	A generating plant owned and partly leased by AEGCo and I&M (1,300 MW, coal-fired) located near Rockport, Indiana
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poors Ratings Service
SO_2	Sulfur dioxide
SO_2 Allowance	An allowance to emit one ton of sulfur dioxide granted under the Clean Air Act Amendments of 1990
SPP	Southwest Power Pool
S&P	Standard & Poors Ratings Service
STP	South Texas Project Nuclear Generating Plant, of which TCC owns 25.2%
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners, including TCC
SWEPCo	Southwestern Electric Power Company, a public utility subsidiary of AEP
TCA	Transmission Coordination Agreement dated January 1, 1997 by and among, PSO, SWEPCo, TCC, TNC and AEPSC, which allocates costs and benefits in connection with the operation of the transmission assets of the four public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
TEA	Transmission Equalization Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
Tractebel	Tractebel Energy Marketing, Inc.
TVA	Tennessee Valley Authority
Virginia Act	Virginia electric restructuring legislation
VSCC	Virginia State Corporation Commission
WVPSC	West Virginia Public Service Commission
West zone public utility subsidiaries	PSO, SWEPCo, TCC and TNC

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its registrant subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its registrant subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

Electric load and customer growth.

Weather conditions, including storms.
Available sources and costs of and transportation for fuels and the creditworthiness of fuel suppliers and transporters.
Availability of generating capacity and the performance of our generating plants.
The ability to recover regulatory assets and stranded costs in connection with deregulation.
The ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
Oversight and/or investigation of the energy sector or its participants.
Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
Our ability to constrain its operation and maintenance costs.
Our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
The economic climate and growth in our service territory and changes in market demand and demographic patterns.
Inflationary trends.
Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy-related commodities.
Changes in the creditworthiness and number of participants in the energy trading market.
Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
Actions of rating agencies, including changes in the ratings of debt.
Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
Changes in utility regulation, including membership and integration into regional transmission structures.
Accounting pronouncements periodically issued by accounting standard-setting bodies.
The performance of our pension and other postretirement benefit plans.
Prices for power that we generate and sell at wholesale.
Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

PART I

ITEM 1. BUSINESS

GENERAL

OVERVIEW AND DESCRIPTION OF SUBSIDIARIES

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a registered public utility holding company under PUHCA that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEPs public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEPs public utility subsidiaries are interconnected, and their operations are coordinated, as a single integrated electric utility system. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio, Texas and Virginia has caused or will cause AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The AEP System is an integrated electric utility system and, as a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The member companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

At December 31, 2004, the subsidiaries of AEP had a total of 19,893 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 934,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2004, APCo and its wholly owned subsidiaries had 2,375 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo integrated into PJM on October 1, 2004.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 707,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2004, CSPCo had 1,150 employees. CSPCos service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo integrated into PJM on October 1, 2004.

I&M (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 579,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2004, I&M had 2,634 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M integrated into PJM on October 1, 2004.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 175,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2004, KPCo had 424 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo integrated into PJM on October 1, 2004.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 46,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company does not own any generating facilities and integrated into PJM on October 1, 2004. It purchases electric power from APCo for distribution to its customers. At December 31, 2004, Kingsport Power Company had 58 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 707,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2004, OPCo had 2,177 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo integrated into PJM on October 1, 2004.

PSO (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 509,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2004, PSO had 1,197 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 444,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2004, SWEPCo had 1,378 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 713,000 retail customers through REPs in southern Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, a municipality, rural electric cooperatives and other market participants. At December 31, 2004, TCC had 933 employees. Among the principal industries served by TCC are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment. In addition to its AEP

System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 188,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2004, TNC had 415 employees. Among the principal industries served by TNCare agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. Wheeling Power Company does not own any generating facilities and integrated into PJM on October 1, 2004. It purchases electric power from OPCo for distribution to its customers. At December 31, 2004, Wheeling Power Company had 61 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M and KPCo. AEGCo has no employees.

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP System companies. The executive officers of AEP and its public utility subsidiaries are all employees of AEPSC. At December 31, 2004, AEPSC had 6,208 employees.

RISK FACTORS

General Risks Of Our Regulated Operations

Rate regulation may delay or deny full recovery of costs. *(Applies to each registrant.)*

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utilitys expenses incurred in a test year. Thus, the rates a utility is allowed to charge may or may not match its expenses at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission 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 full recovery of our costs.

The rates that certain of our utilities may charge their customers may be reduced. *(Applies to AEP and PSO, SWEPCo and TCC, respectively.)*

In February 2003, the OCC required PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCCs requirements indicating that its annual revenues were $41 million less than costs. The OCC Staff and intervenors filed testimony regarding their recommendationsof a decrease in annual existing rates between $15 and $36 million. In addition, one party recommended that $30 million of PSOs natural gas costs not be recovered from customers because it failed to implement a procurement strategy that this party alleged would have resulted in lower natural gas costs. PSO filed rebuttal testimony in February 2005which indicateda decrease of PSOs revenue deficiency from $41 million to $28 million, although much of that decrease includes items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on PSOs revenues, results of operations, cash flows and financial condition.

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and Central and South West Corporation (CSW). The LPSCs merger order also provides that SWEPCos base rates are capped at the present level through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCos current rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in SWEPCos Louisiana jurisdictional base rates. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact SWEPCos future results of operations and cash flows.

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT. In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCCs requested $67 million rate increase. The recommendations ranged from a decrease in existing rates of approximately $100 million to an increase in TCCs current rates of approximately $27 million. The ALJsissuedrecommendations in November 2004, which would reduce TCCs existing rates by $51 million to $78 million from existing levels. The PUCT will hold additional hearings on two major issues in March 2005. The PUCT is expected to issue a decision in the first half of 2005. If the PUCT orders a rate reduction, it could adversely impact TCCs future results of operations and cash flows.

The amount that PSO seeks to recover for fuel costs is currently being reviewed. *(Applies to PSO.)*

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEPs West zone public utility subsidiaries of purchased power costs for periods prior to January 1, 2002. In September 2003, the OCC expanded the case to include a full review of PSOs 2001 fuel and purchased power practices. PSO filed testimony in February 2004. An intervenor, the OCC Staff filed testimonyand theAttorney General of Oklahomahave made filings indicating thatrecovery should be disallowed altogether or reduced in the range of $18 million to $9 million. These filings raised certain issues of an allocation approved under FERC. The ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. The OCC conducted a hearing on the jurisdictional matter in January 2005 but has not issued a decision. If the OCC determines, as a result of the review that a portion of PSOs fuel and purchased power costs should not be recovered, there could be an adverse effect on PSOs results of operations, cash flows and possibly financial condition.

The base rates that certain of our utilities charge are currently capped or frozen. *(Applies to AEP, CSPCo, I&M, OPCo and SWEPCo.)*

Base rates charged to customers in Indiana, Michigan, Louisiana and Ohio are currently either frozen or capped. To the extent our costs in these states exceed the applicable cap or frozen rate, those costs are not recoverable from customers.

Certain of our revenues and results of operations are subject to risks that are beyond our control. *(Applies to each registrant.)*

Unless mitigated by timely and adequate regulatory recovery, the cost of repairing damage to our utility facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events, in excess of reserves established for such repairs, may adversely impact our revenues, operating and capital expenses and results of operations.

We are exposed to nuclear generation risk. *(Applies to AEP, I&M and TCC.)*

Through I&M and TCC, we have interests in four nuclear generating units, which interests equal 2,740 MW, or 7% of our generation capacity. (TCC has entered an agreement to sell its interest in two nuclear generating units.) We are, therefore, also subject to the risks of nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;

- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate; and,

- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could harm our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

The different regional power markets in which we compete or will compete in the future have changing transmission regulatory structures, which could affect our performance in these regions. *(Applies to each registrant.)*

Our results are likely to be affected by differences in the market and transmission regulatory structures in various regional power markets. Problems or delays that may arise in the formation and operation of new regional transmission organizations, or RTOs, may restrict our ability to sell power produced by our generating capacity to certain markets if there is insufficient transmission capacity otherwise available. The rules governing the various regional power markets may also change from time to time which could affect our costs or revenues. Because it remains unclear which companies will be participating in the various regional power markets, or how RTOs will develop or what regions they will cover, we are unable to assess fully the impact that these power markets may have on our business.

AEPs East zone public utility subsidiaries joined PJM on October1, 2004. Two of AEPs west zone public utility subsidiaries are members of SPP. In February 2004, FERC granted RTO status to the SPP, subject to fulfilling specified requirements. In October 2004, the FERC issued an order granting final RTO status to SPP subject to certain filings.

The Louisiana and Arkansas Commissions are concerned about the effect on retail ratepayers of utilities in Louisiana and Arkansas joining RTOs. The Commissions have ordered the utilities in those states, including us, to analyze and submit to the Commissions the costs and benefits of RTO options available to the utilities. The Louisiana Commission has also determined that certain RTO structures that contemplate legally transferring transmission assets to it are presumptively not in the public interest.

To the extent we are faced with conflicting state and Federal requirements as to our participation in RTOs, it could adversely affect our ability to operate and recover transmission costs from retail customers. Management is unable to predict the outcome of these transmission regulatory actions and proceedings or their impact on the timing and operation of RTOs, our transmission operations or future results of operations and cash flows.

The FERC may reduce the amount we may charge third parties for using our transmission facilities. *(Applies to AEP and AEPs East zone public utility subsidiaries .)*

In July 2003, the FERC issued an order directing PJM and the MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs revenue distribution protocols.

AEP and several other utilities in the Combined Footprint filed a proposal for new rates to become effective December 1, 2004. In November 2004, FERC eliminated the T&O rates and replaced the rates temporarily through March 2006 withseams elimination cost adjustment (SECA) fees. AEPs East zone public utility subsidiaries received approximately $1 96 million of T&O rate revenues for the twelve months ended September 30, 2004, the last twelve months prior to joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA fees was $171 million. Effective April 2006, all transmission costs that would otherwise have been defrayed by T&O rates in the Combined Footprint will be subject to recovery from native load customers of AEPs East zone public utility subsidiaries. At this time, management is unable to predict whether any resultant increase in rates applicable to AEPs internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues, and unless any increase in AEPs East zone public utility subsidiaries transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected.

We are subject to regulation under the Public Utility Holding Company Act of 1935. *(Applies to each registrant.)*

Our system is subject to the jurisdiction of the SEC under PUHCA. The rules and regulations under PUHCA impose a number of restrictions on the operations of registered holding company systems. These restrictions include a requirement that the SEC approve in advance securities issuances, sales and acquisitions of utility assets, sales and acquisitions of securities of utility companies and acquisitions of other businesses. PUHCA also generally limits the operations of a registered holding company to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules limit the dividends that our subsidiaries may pay from unearned surplus.

Our merger with CSW may ultimately be found to violate PUHCA. *(Applies to AEP, PSO, SWEPCo, TCC and TNC.)*

We acquired CSW in a merger completed on June 15, 2000. Among the more significant assets we acquired as a result of the merger were four additional domestic electric utility companies - PSO, SWEPCo, TCC and TNC. On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SECs June 14, 2000 order approving the merger failed to properly find that the merger meets the requirements of PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCAs requirement that the electric utilities be physically interconnected and confined to a single area or region. In August 2004, the SEC announced it would conduct hearings on this issue. A hearing was held January 10, 2005 before an ALJ. An initial decision is expected from the ALJ later this year. The SEC will have the opportunity to review the initial decision.

We believe that the merger meets the requirements of PUHCA and expect the matter to be resolved favorably.We can give no assurance, however, that: (i) the SEC or any applicable court review will find that the merger complies with PUHCA, or (ii) the SEC or any applicable court review will not impose material adverse conditions on us in order to find that the merger complies with PUHCA. If the merger were ultimately found to violate PUHCA, we could be requiredto take remedial actions or divest assets, which could harm our results of operations or financial condition.

We operate in a non-uniform and fluid regulatory environment. *(Applies to each registrant.)*

In most instances and in varying degrees, the rates charged by the domestic utility subsidiaries are approved by the FERC and the eleven state utility commissions. FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail generation and distribution rates. Several of the eleven state retail jurisdictions in which our domestic electric utilities operate have enacted restructuring legislation. Restructuring legislation in Texas requires the legal separation of generation and related assets from the transmission and distribution assets of the electric utilities in that state. In Ohio, we are complying with restructuring legislation through the continued functional separation of the operations of our Ohio utility subsidiaries. As a result of restructuring legislation in Texas and Ohio, a significant portion of our domestic generation is no longer directly regulated by state utility commissions as to rates. TCC has sold some of its generation in Texas and is in the process of selling its remaining generation. Our utility operations in the remaining state retail jurisdictions that have not enacted any restructuring legislation currently plan to adhere to the vertically-integrated utility model with cost recovery through regulated rates.

Our business plan is based on the regulatory framework as described. There can be no assurance that the states that have pursued restructuring will not reverse such policies; nor can there be assurance that the states that have not enacted restructuring legislation will not do so in the future. In addition to the multiple levels of regulation at the state level in which we operate, our business is subject to extensive federal regulation. There can be no assurance that the federal legislative and regulatory initiatives (which have occurred over the past few years and which have generally facilitated competition in the energy sector) will continue or will not be reversed.

Further alteration of the regulatory landscape in which we operate will impact the effectiveness of our business plan and may, because of the continued uncertainty, harm our financial condition and results of operations.

Risks Related to Market, Economic or International Financial Volatility

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant other than AEGCo.)*

Following the bankruptcy of Enron, the credit ratings agencies initiated a thorough review of the capital structure and the quality and stability of earnings of energy companies, including us. The agencies made ratings changes at that time. Further negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

Moodys has assigned an investment grade credit rating to the senior unsecured long-term debt of each registrant other than AEGCo (collectively, the Rated Issuers). Moodys has further assigned an outlook of stable for each of the Rated Issuers other than AEP, which Moodys assigned an outlook of positive in 2004. S&P has also assigned an investment grade credit rating to the senior unsecured long-term debt of each of the Rated Issuers. S&P has assigned an outlook of stable for each of the Rated Issuers. Fitch has also assigned an investment grade credit rating (with stable outlook) to the senior unsecured long-term debt of each of the Rated Issuers. Apart from Moodys improving the outlook on AEP noted above, none of these ratings was adjusted by any rating agency during 2004.

Moodys has assigned AEP a short-term debt rating of P-3. S&P has assigned AEP a short-term debt rating of A-2. Fitch has assigned AEP a short-term debt rating of F-2. As a result of the split rating, AEPs access to the commercial paper market may be limited and the short-term borrowing costs of each registrant may increase (because AEPs subsidiaries conduct short-term borrowing through AEP and on the same terms available to AEP).

If Moodys or S&P were to downgrade the long-term rating of any of the Rated Issuers **,** particularly below investment grade, the borrowing costs of that Rated Issuer would increase, which would diminish its financial results. In addition, it would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources could decrease.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

The underfunded conditionof our retirement plans may require additional significant contributions. *(Applies to each registrant.)*

AEP provides defined benefit pension plans (Pension Plans) for the employees of our subsidiaries. In addition, AEP provides health care and life insurance benefit plans for retired employees.

Low prevailing interest rates have increased the pension plans liability. The combined Pension Plans liabilities based on service and pay to date (Accumulated Benefit Obligation) exceeded the value of the assets at December 31, 2004. As of December 31, 2004, the fair value of the Pension Plans assets was $3.56 billion while the Accumulated Benefit Obligation was estimated at $4.0 billion, an underfunding of approximately $450 million. For the individual pension plans that were underfunded based on the Accumulated Benefit Obligation, underfunding totaled approximately $474 million. In order to fund the qualified pension plans fully by the end of 2005, a discretionary contribution of $200 million was made in the fourth quarter of 2004 and discretionary contributions of $100 million per quarter are expected in 2005.

AEP also made contributions of $137 million to postretirement health care and life insurance benefits trust funds in 2004, and expects to contribute significant amounts in the future.

We cannot predict the future performance of the investment markets. A downturn in the investment markets could have a material negative impact on the net asset value of the plans trust accounts and increase the underfunding of the Pension Plans, net of benefit obligations. This may necessitate significant cash contributions to the Pension Plans. Changes in interest rates may also materially affect the pension and postretirement health care and life insurance benefit liabilities and the cash contributions needed to fund those liabilities. Changes in the laws and regulations governing the plans may increase or decrease the required contributions.

Our operating results may fluctuate on a seasonal and quarterly basis . *(Applies to each registrant.)*

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. We expect that unusually mild weather in the future could diminish our results of operations and harm our financial condition.

Changes in technology may significantly affect our business by making our power plants less competitive . *(Applies to each registrant.)*

A key element of our business model is that generating power at central power plants achieves economies of scale and produces power at relatively low cost. There are other technologies that produce power, most notably fuel cells, microturbines, windmills and photovoltaic (solar) cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central power station electric production. If this were to happen and if these technologies achieved economies of scale, our market share could be eroded, and the value of our power plants could be reduced. Changes in technology could also alter the channels through which retail electric customers buy power, thereby harming our financial results.

Changes in commodity prices may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance . *(Applies to each registrant.)*

We are heavily exposed to changes in the price and availability of coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise not honored, we may not be able to purchase coal on terms as favorable as the current contracts.

We also own natural gas-fired facilities, which increases our exposure to the more volatile market prices of natural gas.

Changes in the cost of coal or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal or natural gas costs, we may be unable to pass on the changes in costs to our customers. In addition, the prices we can charge our retail customers in some jurisdictions are capped and our fuel recovery mechanisms in other states are frozen for various periods of time.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

At times, demand for power could exceed our supply capacity . *(Applies to each registrant other than TCC and TNC.)*

We are currently obligated to supply power in parts of eleven states. From time to time because of unforseen circumstances the demand for power required to meet these obligations could exceed our available generation capacity. If this occurs, we would have to buy power on the market. We may not always have the ability to pass these costs on to our customers because some of the states we operate in do not allow us to increase our rates in response to increased fuel cost charges. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage was brief, we could suffer substantial losses that could diminish our results of operations.

Risks Relating To State Restructuring

We have limited ability to pass our costs of production on to our customers. *(Applies to each registrant.)*

We are exposed to risk from changes in the market prices of coal and natural gas used to generate power where generation is no longer regulated or where existing fuel clauses are suspended or frozen. Recently, the price of coal and natural gas has increased materially. The protection afforded by retail fuel clause recovery mechanisms has been eliminated by the implementation of customer choice in Ohio and in the ERCOT area of Texas. There may be similar risks should customer choice be similarly implemented in other states. Because the risk of generating costs cannot be passed through to customers as a matter of right in Ohio and the ERCOT area of Texas, we retain these risks.

A fuel clause in West Virginia has been suspended per a settlement reached in a state restructuring proceeding. However, as restructuring has not been implemented in West Virginia, the fuel clause may be reactivated. An extension of the currently pending fuel clause in Indiana is being negotiated.

Our default service obligations in Ohio do not restrict customers from switching suppliers of power. *(Applies to AEP, CSPCo and OPCo.)*

Those default service customers that we serve in Ohio may choose to purchase power from alternative suppliers. Should they choose to switch from us, our sales of power may decrease. Customers originally choosing alternative suppliers may switch to our default service obligations. This may increase demand above our facilities available capacity. Thus, any such switching by customers could have an adverse effect on our results of operations and financial position. Conversely, to the extent the power sold to meet the default service obligations could have been sold to third parties at more favorable wholesale prices, we will have incurred potentially significant lost opportunity costs.

If CSPCo and OPCo are unable to remain functionally separated, they will need SEC approval to legally separate their assets. *(Applies to CSPCo and OPCo.)*

Ohio has enacted restructuring legislation in the Ohio Act. CSPCo and OPCo each currently comply with the Ohio Act as a functionally separated electric utility. The PUCO has approved the rate stabilization plan that does not contemplate legal separation at least through 2008. However, we can give no assurance that we can remain functionally separated following that. If CSPCo and OPCo are unable to remain functionally separated and we are required to legally separate, they would need SEC approval to legally separate.

Some laws and regulations governing restructuring of the wholesale generation market in Michigan and Virginia have not yet been interpreted or adopted and could harm our business, operating results and financial condition. *(Applies to AEP and APCo and I&M, respectively.)*

While the electric restructuring laws in Michigan and Virginia established the general framework governing the retail electric market, the laws required the utility commission in each state to issue rules and determinations implementing the laws. Some of the regulations governing the retail electric market have not yet been adopted by the utility commission in each state. These laws, when they are interpreted and when the regulations are developed and adopted, may harm our business, results of operations and financial condition. Virginia restructuring legislation was enacted in 1999 providing for retail choice of generation suppliers to be phased in over two years beginning January1, 2002. It required jurisdictional utilities to unbundle their power supply and energy delivery rates and to file functional separation plans by January 1, 2002. APCo filed its plan with VSCC and, following VSCC approval of a settlement agreement, now operates in Virginia as a functionally separated electric utility charging unbundled rates for its retail sales of electricity. The settlement agreement addressed functional separation, leaving decisions related to legal separation for later VSCC consideration. Legislation in Virginia has been adopted which extends a cap on electricity rates until 2010.

Customer choice commenced for I&Ms Michigan customers on January 1, 2002. Rates for retail electric service for I&Ms Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2004, none of I&Ms Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&Ms Michigan service territory.

There is uncertainty as to our recovery of deferred fuel balances and stranded costs resulting from industry restructuring in Texas. *(Applies to AEP and TCC.)*

In 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the true-up proceeding described below. This reconciliation covers the period from July 1998 through December 2001. The PUCT will review an ALJ report addressing the reconciliation and will likely issue a decision in the first quarter of 2005. The over-recovery balance and the subsequent provisions for probable disallowances totaled $212 million, including interest, at December 31, 2004. The PUCT will net the final amount against recoverable amounts determined by the true-up proceeding.

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We have elected to use the sale of assets method to determine the market value of all of the generation assets of TCC for stranded cost purposes. The amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCCs generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. TCCs sale of its generating assets will be subject to a review in a true-up proceeding conducted by the PUCT. TCCs recorded net regulatory asset for amounts subject to approval in the true-up proceeding, net of the deferred fuel over-recovery described above, is approximately $1.6 billion. We estimate that TCCs true-up filing will exceed the total of its recorded net regulatory asset. Management expects that the true-up proceeding will be contentious and could possibly result in disallowances. If we are unable, after the true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related net regulatory assets, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Collection of our revenues in Texas is concentrated in a limited number of REPs. *(Applies to AEP, TCC and TNC.)*

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately forty three REPs. Adverse economic conditions, structural problems in the new Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows thereby have an adverse effect on our liquidity.

We may not be able to respond effectively to competition. *(Applies to each registrant.)*

We may not be able to respond in a timely or effective manner to the many changes in the power industry that may occur as a result of regulatory initiatives to increase competition. These regulatory initiatives may include deregulation of the electric utility industry in some markets. To the extent that competition increases, our profit margins may be negatively affected. Industry deregulation may not only continue to facilitate the current trend toward consolidation in the utility industry but may also encourage the disaggregation of other vertically integrated utilities into separate generation, transmission and distribution businesses. As a result, additional competitors in our industry may be created, and we may not be able to maintain our revenues and earnings levels or pursue our growth strategy.

While demand for power is generally increasing throughout the United States, the rate of construction and development of new, more efficient electric generation facilities may exceed increases in demand in some regional electric markets. The start-up of new facilities in the regional markets in which we have facilities could increase competition in the wholesale power market in those regions, which could harm our business, results of operations and financial condition. Also, industry restructuring in regions in which we have substantial operations could affect our operations in a manner that is difficult to predict, since the effects will depend on the form and timing of the restructuring.

Risks Related to Environmental Regulation

Our costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to each registrant other than TCC and TNC.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past and we expect that they will increase in the future. Costs of compliance with environmental regulations could harm our industry, our business and our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that carbon dioxide emissions from power generating facilities constitute a public nuisance under federal common law. The suits seek injunctive relief in the form of specific emission reduction commitments from the defendants. While we believe the claims are without merit, the costs associated with reducing carbon dioxide emissions could harm our business and our results of operations and financial position.

We anticipate that we will incur considerable capital costs for compliance. *(Applies to each registrant other than TCC and TNC.)*

Most of our generating capacity is coal burning. We plan to install new emissions control equipment and may be required to upgrade existing equipment, purchase emissions allowances or reduce operations. We estimate that we will invest approximately $600 million to comply with existing federal and state regulations designed to limit nitrogen oxide (NOx) emissions and approximately $1.2 billion to comply with existing federal and state regulations designed to limit sulfur dioxide (SO_2) emissions. We estimate that we will invest approximately $1.8 billion (and an additional $150 million in operation and maintenance expenses) to comply with currently proposed, but as yet unadopted, federal regulations designed to limit NOx, SO_2 and mercury emissions through 2010, assuming certain contingencies. Between 2011 and 2020 we expect to incur additional costs for pollution control technology retrofits and investment of $1.6 billion. However, post-2010 capital investment estimates are quite uncertain. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules, and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from the estimates. All of the costs are incremental to our current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs should be recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

Governmental authorities may assess penalties on us for failures to comply with environmental laws and regulations. *(Applies to each registrant.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the Clean Air Act. Federal EPA and a number of states alleged that we and eleven unaffiliated utilities modified certain units at coal-fired generating plants in violation of the Clean Air Act. Federal EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period.

If these actions are resolved against us, substantial modifications of our existing coal-fired power plants would be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Other parties have settled similar lawsuits. An unaffiliated utility which operates certain plants jointly owned by CSPCo reached a tentative agreement to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing and a settlement could impact the operation of certain of the jointly owned plants. Until a final settlement is reached, CSPCo will be unable to determine the settlements impact on its jointly owned facilities and its future results of operations and cash flows.

Risks Related to Power Trading and Wholesale Businesses

Our revenues and results of operations are subject to market risks that are beyond our control. *(Applies to each registrant.)*

We sell power from our generation facilities into the spot market or other competitive power markets or on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, we are not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices may fluctuate substantially over relatively short periods of time. It is reasonable to expect that trading margins may erode as markets mature and that there may be diminished opportunities for gain should volatility decline. In addition, FERC, which has jurisdiction over wholesale power rates, as well as independent system operators that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Fuel prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel costs. These factors could reduce our margins and therefore diminish our revenues and results of operations.

Volatility in market prices for fuel and power may result from:

- weather conditions;

seasonality;

power usage;

illiquid markets;

transmission or transportation constraints or inefficiencies;

availability of competitively priced alternative energy sources;

demand for energy commodities;

natural gas, crude oil and refined products, and coal production levels;

natural disasters, wars, embargoes and other catastrophic events; and federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and e mission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. *(Applies to each registrant.)*

Our power trading (including coal, gas and emission allowances trading and power marketing) activities expose us to risks of commodity price movements. We attempt to manage our exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within established guidelines, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading and risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be wrong or inaccurate.

Our financial performance may be adversely affected if we are unable to operate our pooled electric generating facilities successfully. *(Applies to each registrant.)*

Our performance is highly dependent on the successful operation of our electric generating facilities. Operating electric generating facilities involves many risks, including:

operator error and breakdown or failure of equipment or processes;

operating limitations that may be imposed by environmental or other regulatory requirements;

labor disputes;

fuel supply interruptions; and

catastrophic events such as fires, earthquakes, explosions, terrorism, floods or other similar occurrences.

A decrease or elimination of revenues from power produced by our electric generating facilities or an increase in the cost of operating the facilities would adversely affect our results of operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We are contractually required to operate a power generation facility that we have agreed to lease but the energy sales market for the facilitys excess energy is over-supplied. *(Applies to AEP.)*

We have agreed to lease from Juniper Capital L.P. a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana. We sublease the Facility to Dow. We operate the Facility for Dow. Dow uses a portion of the energy produced by the Facility and sells the excess power to us. We have agreed to sell up to all of the excess 800 MW to a third party at a price that is currently in excess of market. This agreement is now being litigated. If it is unenforceable, we will be required to find new purchasers for up to 800MW. There can be no assurance that this power will be sold at prices that will exceed our costs to produce it. If that were the case, as a result of our obligations to Dow, we would be required to operate the Facility at a loss.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power. *(Applies to each registrant.)*

We depend on transmission facilities owned and operated by other unaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a regions power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity and gas, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We do not fully hedge against price changes in commodities. *(Applies to each registrant.)*

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP, except for last paragraph, which applies to each registrant.)*

In 2002, certain of our subsidiaries filed claims against Enron Corp. (Enron) and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enrons bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enrons bankruptcy.

Cushion gas use agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (together with BOA, BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. We are currently litigating the rights to the cushion gas.

In February 2004, in connection with BOAs dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enrons attempted rejection of these agreements. In January 2005 we sold a 98% controlling interest in HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA.

Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEPs offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP has asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. The parties are currently in non-binding court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enrons claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in non-binding court-sponsored mediation. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Potential for disruption exists if the delay of a FERC market power mitigation order is lifted. *(Applies to each registrant.)*

In July 2004, the FERC issued an order directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. We have presented evidence to FERC to demonstrate that we do not possess market power in geographic areas where we sell wholesale power. In a December 2004 order, FERC found that AEP passed the screens in PJM and ERCOT, but not in the SPP area. Because AEP did not pass the market share screen in SPP, FERC initiated a proceeding under Section 206 of the FPA in which AEP is rebuttably presumed to possess market power in SPP. Consequently, our revenues from sales in SPP at market based rates after March 6, 2005 will be collected subject to refund to the extent that prices are ultimately found not to be just and reasonable. In February 2005 AEP filed with the FERC revisions to its market-based rate tariffs that cap the rates of wholesale power that AEP delivers within its control area of the SPP. We are unable to predict the timing or impact of any further action by the FERC.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2004 are as follows:

Description	**AEP System(a)**	**APCo**	**CSPCo**	**I&M**	**KPCo**
	(in thousands)				
Utility Operations:					
Retail Sales					
Residential Sales	$ 3,249,000	$ 635,905	$522,871	$367,015	$ 128,982
Commercial Sales	2,326,000	323,623	467,628	288,046	75,584
Industrial Sales	2,051,000	349,674	131,129	342,622	109,767
Total Other Retail Sales	97,000	41,735	15,328	6,482	1,009
Total Retail	7,723,000	1,350,937	1,136,956	1,004,165	315,342
Wholesale					
System Sales & Transmission	2,330,000	296,877	168,757	343,620	69,023
Risk Management Realized	73,000	18,120	8,029	14,473	7,687
Risk Management Mark-to-Market	(48,000)	192	5,563	-	-
Total Wholesale	2,355,000	315,189	182,349	358,093	76,710
Other Operating Revenues	495,000	65,493	34,161	38,148	16,971
Sales to Affiliates	-	216,563	80,115	261,174	41,590
Gross Utility Operating Revenues	10,573,000	1,948,182	1,433,581	1,661,580	450,613
Provision for Rate Refund	(60,000)	-	-	-	-
Net Utility Operations	10,513,000	1,948,182	1,433,581	1,661,580	450,613
Investments - Gas Operations	3,064,000	-	-	-	-
Investments - Other	480,000	-	-	-	-
Total Revenues	$ 14,057,000	$ 1,948,182	$1,433,581	$1,661,580	$ 450,613

Description	**OPCo**	**PSO**	**SWEPCo**	**TCC (b)**	**TNC(b)**
			(in thousands)		
Utility Operations:					
Retail Sales					
Residential Sales	$471,515	$395,571	$ 331,478	$ 216,954	$ 56,033
Commercial Sales	312,264	272,583	280,244	162,487	28,300
Industrial Sales	534,800	256,944	205,948	35,129	8,301
Total Other Retail Sales	8,559	92,325	6,220	9,064	11,386
Total Retail	1,327,138	1,017,423	823,890	423,634	104,020
Wholesale					
System Sales & Transmission	250,001	(7,230)	122,798	636,621	307,926
Risk Management Realized	10,289	13	(267)	234	503
Risk Management Mark-to-Market	9,002	-	571	3,628	1,528
Total Wholesale	269,292	(7,217)	123,102	640,483	309,957
Other Operating Revenues	58,451	26,625	76,124	127,010	37,664
Sales to Affiliates	581,515	10,690	71,190	47,039	51,680
Gross Utility Operating Revenues	2,236,396	1,047,521	1,094,306	1,238,166	503,321
Provision for Rate Refund	-	-	(6,960)	(62,900)	(11,176)
Net Utility Operations	2,236,396	1,047,521	1,087,346	1,175,266	492,145

Investments - Gas Operations	-	-	-	-	-
Investments - Other	-	-	-	-	-
Total Revenues	$2,236,396	$1,047,521	$ 1,087,346	$ 1,175,266	$ 492,145

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated, including AEGCos total revenues of $241,788,000 for the year ended December 31, 2004, all of which resulted from its wholesale business, including its marketing and trading of power.

(b) TCC and TNC wire sales to REPs moved to retail classes of customer.

HOLDING COMPANY REGULATION

The provisions of PUHCA, are administered by the SEC. PUHCA regulates many aspects of a registered holding company system, such as the AEP System. PUHCA limits the operations of a registered holding company system to a single integrated public utility system and such other businesses as are incidental or necessary to the operations of the system. In addition, PUHCA governs, among other things, financings, sales or acquisitions of utility assets and intra-system transactions.

PUHCA and the rules and orders of the SEC currently require that transactions between associated companies in a registered holding company system be performed at cost, with limited exceptions. Over the years, the AEP System has developed numerous affiliated service, sales and construction relationships and, in some cases, invested significant capital and developed significant operations in reliance upon the ability to recover its full costs under these provisions.

Legislation has been introduced in numerous sessions of Congress that would repeal PUHCA, but no such legislation has passed.

AEP-CSW MERGER

On June 15, 2000, a wholly owned merger subsidiary of AEP merged with and into CSW (now known as AEP Utilities, Inc.). As a result, CSW became a wholly owned subsidiary of AEP. The four wholly owned public utility subsidiaries of CSWPSO, SWEPCo, TCC and TNCbecame indirect wholly owned public utility subsidiaries of AEP as a result of the merger. The merger was approved by the FERC and the SEC.

On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to properly explain how the merger met the requirements of PUHCA and remanded the case to the SEC for further review. The court held that the SEC had not adequately explained its conclusions that the merger met PUHCA requirements that the merging entities be physically interconnected and that the combined entity was confined to a single area or region. A hearing was held January 10, 2005 before an ALJ. An initial decision is expected from the ALJ later this year. The SEC will have the opportunity to review the initial decision.

Management believes that the merger meets the requirements of PUHCA and expects the matter to be resolved favorably.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs, acquisitions and construction. The companies periodically issue long-term debt to reduce short-term debt. In recent history short-term debt has been provided by AEPs commercial paper program and revolving credit facilities. Proceeds were made available to subsidiaries under the AEP corporate borrowing program. Throughout 2004, AEP was successful in accessing the commercial paper market. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity.

AEPs revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and a $50 million cross-acceleration provision. At December 31, 2004, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency would be considered an immediate termination event. See *Managements Financial Discussion and Analysis of Results of Operations* , included in the 2004 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEPs credit agreements.

AEPs subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as leasing arrangements, including the leasing of utility assets and coal mining and transportation equipment and facilities.

Credit Ratings

In 2004, AEP executives met with representatives of the rating agencies to review AEP and its registrant subsidiaries historical and forecasted financial condition, operations and other matters.

In August 2004, Moodys placed AEP on positive outlook. In July 2004, S&P upgraded the senior secured ratings of PSO and SWEPCo to A- from BBB. To date, S&P has not changed the ratings of AEP or any other of its rated subsidiaries. Fitch did not change the ratings of AEP or its rated subsidiaries during 2004.

The senior secured ratings on certain of AEPs rated subsidiaries will be removed where secured debt no longer exists.

See *Managements Financial Discussion and Analysis of Results of Operations* , included in the 2004 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants other than AEGCo.

ENVIRONMENTAL AND OTHER MATTERS

General

AEPs subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that are potentially material to the AEP system include:

The CAA and CAAA and state laws and regulations (including State Implementation Plans) that require compliance, obtaining permits and reporting as to air emissions. See *Managements Financial Discussion and Analysis of Results of Operations* under the heading entitled *The Current Air Quality Regulatory Framework* .

Litigation with the federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating plants required additional permitting or pollution control technology. See *Managements Financial Discussion and Analysis of Results of Operations* under the headings entitled *The Current Air Quality Regulatory Framework* and *New Source Review Litigation* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies* , included in the 2004 Annual Reports, for further information.

Rules issued by the EPA and certain states that require substantial reductions in SO_2 , mercury and NOx emissions, some of which became effective in 2003. The remaining compliance dates and proposals would take effect periodically through as late as 2018. AEP is installing (or has installed) emission control technology and is taking other measures to comply with required reductions. See *Managements Financial Discussion and Analysis of Results of Operations* under the headings entitled *Future Reduction Requirements for NOx, SO_2 and Hg* and *Estimated Air Quality Investments* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies* , included in the 2004 Annual Reports under the heading entitled *NOx Reductions* for further information.

CERCLA, which imposes upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites, costs for environmental remediation. AEP does not, however, anticipate that any of its currently identified CERCLA-related issues will result in material costs or penalties to the AEP System. See *Managements Financial Discussion and Analysis of Results of Operations* , included in the 2004 Annual Reports, under the heading entitled *Superfund and State Remediation* for further information .

The Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits. In July 2004, the EPA adopted a new Clean Water Act rule to reduce the number of fish and other aquatic organisms killed at once-through cooled power plants. See *Managements Financial Discussion and Analysis of Results of Operations* , included in the 2004 Annual Reports, under the heading entitled *Clean Water Act Regulation* for additional information.

Solid and hazardous waste laws and regulations, which govern the management and disposal of certain wastes. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion byproducts, which the EPA has determined are not hazardous waste governed subject to RCRA.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. See *Managements Financial Discussion and Analysis of Results of Operations* , included in the 2004 Annual Reports, under the heading entitled *Environmental Matters* for information on current environmental issues .

If our expenditures for pollution control technologies, replacement generation and associated operating costs are not recoverable from customers through regulated rates (in regulated jurisdictions) or market prices (in deregulated jurisdictions), those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System.

See *Managements Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, included in the 2004 Annual Reports, for further information with respect to environmental matters.

Environmental Investments

Investments related to improving AEP System plants environmental performance and compliance with air and water quality standards during 2003 and 2004 and the current estimate for 2005 are shown below. Substantial investments in addition to the amounts set forth below are expected by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted. Future investments could be significantly greater if litigation regarding whether AEP properly installed emission control equipment on its plants is resolved against any AEP subsidiaries or emissions reduction requirements are accelerated or otherwise become more onerous. See *Managements Financial Discussion and Analysis of Results of Operations* under the headings entitled *Future Reduction Requirements for NOx, SO_2 and Hg* and *Estimated Air Quality Investments* ; and Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies*, included in the 2004 Annual Reports, for more information regarding this litigation and environmental expenditures in general.

	2003 Actual	**2004 Actual**	**2005 Estimate**
		(in thousands)	
AEGCo	$ 11,800	$6,500	$2,100
APCo	70,600	165,800	309,600
CSPCo	31,400	26,600	23,400
I&M	14,900	11,900	82,300
KPCo	40,500	2,900	8,500
OPCo	40,000	136,400	485,400
PSO	1,700	100	500
SWEPCo	3,200	4,100	24,400
TCC	500	0	0
TNC	2,600	0	400
AEP System	$ 217,200	$354,300	$936,600

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEPs business operations. Utility operations include (i) the generation, transmission and distribution of electric power to retail customers and (ii) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEPs public utility subsidiaries performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

ELECTRIC GENERATION

Facilities

AEPs public utility subsidiaries own approximately 34,500 MW of domestic generation. See *Deactivation and Disposition of Generating Facilities* for a discussion of planned and completed sales of certain of AEPs generating facilities. Pursuant to regulatory orders, the AEP public utility subsidiaries operate their generating facilities as a single interconnected and coordinated electric utility system. See *Item 2 Properties* for more information regarding AEPs generation capacity.

AEP Power Pool and CSW Operating Agreement

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each companys member-load-ratio. The Interconnection Agreement has been approved by the FERC.

The member-load ratio is calculated monthly by dividing such companys highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. As of December 31, 2004, the member-load ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	6,298	30.7
CSPCo	3,623	17.6
I&M	4,051	19.8
KPCo	1,478	7.2
OPCo	5,059	24.7

Although customer choice was adopted in Ohio in 2001, CSPCo and OPCo plan to remain functionally separated through at least December 31, 2008 as authorized by their rate stabilization plan approved by the PUCO. See *Managements Financial Discussion and Analysis and Financial Condition,* under the heading entitled *Regulatory Matters, Ohio* included in the 2004 Annual Reports and Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring* , included in the 2004 Annual Reports, for more information.

The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement and AEP System Interim Allowance Agreement during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
APCo	$ 127,000	$ 218,000	$ 239,400
CSPCo	267,000	276,800	284,900
I&M	(113,600)	(118,800)	(141,500)
KPCo	46,500	38,400	31,600
OPCo	(326,900)	(414,400)	(414,400)

PSO, SWEPCo, TCC, TNC, and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the west zone public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP west zone public utility subsidiaries as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverers incremental cost plus a portion of the recipients savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties. Upon the sale of its generation assets, TCC will no longer supply generating capacity under the CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
PSO	$ 53,700	$ 44,000	$ 55,000
SWEPCo	(67,800)	(46,600)	(59,800)
TCC	(15,400)	(29,500)	1,100
TNC	29,500	32,100	3,700

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, REPs) by such public utility subsidiary at rates approved (other than in the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation. See *Regulation Rates* .

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See *Risk Management and Trading* for a discussion of the trading and marketing of such power.

AEPs System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEPs east and west zone operating subsidiaries. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

Risk Management and Trading

As agent for AEPs public utility subsidiaries, AEP sells excess power into the market and engages in power and natural gas risk management and trading activities focused in regions in which AEP traditionally operates. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2004, counterparties have posted approximately $98 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEPs public utility subsidiaries (while, as of that date, AEPs public utility subsidiaries had posted approximately $2 million with counterparties). Since open trading contracts are valued based on changes in market power prices, exposures change daily.

Fuel Supply

The following table shows the sources of power generated by the AEP System:

	2002	2003	2004
Coal	78%	80%	83%
Natural Gas	8%	7%	5%
Nuclear	11%	9%	12%
Hydroelectric and other	3%	4%	1%

Variations in the generation of nuclear power are primarily related to refueling and maintenance outages. Variations in the generation of natural gas power are primarily related to the availability of cheaper alternatives to fulfill certain power requirements and the deactivation or sale of certain gas-fired plants owned by TCC and TNC. Price increases in one or more fuel sources relative to other fuels generally result in increased use of other fuels.

Coal and Lignite *:* AEPs public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations, short-term, and spot agreements with various producers and coal trading firms. The price for most coal fuels has increased resulting in a trend that may continue. Management has responded to increases in the price of coal by rebalancing the coal used in its generating facilities with products from different coal regions and sources of differing heat rates and sulfur content. This rebalancing is an ongoing process that is expected to continue. Management believes, but cannot provide assurances that, AEPs public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. See *Investments-Other* for a discussion of AEPs coal marketing and transportation operations.

The following table shows the amount of coal delivered to the AEP System during the past three years and the average delivered price of spot coal purchased by System companies:

	2002	2003	2004
Total coal delivered to AEP operated plants (thousands of tons)	76,442	76,042	71,778
Average price per ton of spot-purchased coal	$27.06	$28.91	$33.83

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers usage of electric power, space limitations, the rate of consumption at particular plants, labor issues and weather conditions which may interrupt deliveries. At December 31, 2004, the Systems coal inventory was approximately 31 days of normal usage. This estimate assumes that the total supply would be utilized through the operation of plants that use coal most efficiently.

In cases of emergency or shortage, system companies have developed programs to conserve coal supplies at their plants. Such programs have been filed and reviewed with officials of federal and state agencies and, in some cases, the relevant state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agency.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to ratemaking principles by which such electric utilities would be compensated. In addition, the federal government is authorized, under prescribed conditions, to reallocate coal and to require the transportation thereof, for the use at power plants or major fuel-burning installations experiencing fuel shortages.

Natural Gas *:* T hrough its public utility subsidiaries, AEP consumed over 94 billion cubic feet of natural gas during 2004 for generating power. A majority of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves reliability. A portfolio of long-term, monthly and seasonal firm purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant.

Nuclear: I&M and STPNOC have made commitments to meet their current nuclear fuel requirements of the Cook Plant and STP, respectively. Steps currently are being taken, based upon the planned fuel cycles for the Cook Plant, to review and evaluate I&Ms requirements for the supply of nuclear fuel. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted. TCC and the other STP participants have entered into contracts with suppliers for (i) 100% of the uranium concentrate sufficient for the operation of both STP units through spring 2011 and (ii) 100% of the uranium concentrate needed for STP through spring 2011. See *Deactivation and Disposition of Generation Facilities* for more information about TCCs interest in STP.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M has completed modifications to its spent nuclear fuel storage pool. AEP anticipates that the Cook Plant has storage capacity to permit normal operations through 2012. STP has on-site storage facilities with the capability to store the spent nuclear fuel generated by the STP units over their licensed lives.

Nuclear Waste and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plants safely. The ultimate cost of retiring the Cook Plant and STP may be materially different from estimates and funding targets as a result of the:

Type of decommissioning plan selected;

Escalation of various cost elements (including, but not limited to, general inflation);

Further development of regulatory requirements governing decommissioning;

Limited availability to date of significant experience in decommissioning such facilities;

Technology available at the time of decommissioning differing significantly from that assumed in studies;

Availability of nuclear waste disposal facilities;

Availability of a Department of Energy facility for permanent storage of spent nuclear fuel; and

Approval of the Cook Plants license extension.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant and STP will not be significantly different than current projections. See *Deactivation and Disposition of Generation Facilities* for more information about TCCs interest in STP.

See *Managements Financial Discussion and Analysis of Results of Operations* and Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies* , included in the 2004 Annual Reports, for information with respect to nuclear waste and decommissioning and related litigation.

Low-Level Radioactive Waste *:* The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan and Texas do not currently have disposal sites for such waste available. AEP cannot predict when such sites may be available, but South Carolina and Utah operate low-level radioactive waste disposal sites and accept low-level radioactive waste from Michigan and Texas. AEPs access to the South Carolina facility is currently allowed through the end of fiscal year 2008. There is currently no set date limiting AEPs access to the Utah facility. See *Deactivation and Disposition of Generation Facilities* for more information about TCCs interest in STP.

Deactivation and Disposition of Generation Facilities

Pursuant to ERCOTs approval, AEP deactivated 16 gas-fired power plants (8 TCC plants and 8 TNC plants). Separately, TCC conducted an auction to sell all of its generation facilities in Texas to establish the market value of the assets and TCCs stranded costs in accordance with the Texas Act. See *Texas Regulatory Assets and Stranded Cost Recovery and Post-Restructuring Wires Charges* . The competitive bidding process began in June 2003 after the PUCT issued a rule confirming TCCs ability to establish the value of its generation assets and amount of stranded costs by selling the generation assets. The PUCT engaged a consultant and designated a team to monitor the auction and advise TCC on the sale of its generating assets, including requirements of the Texas Act for establishing stranded costs.

The assets had a generating capacity of 4,497 MW and included the eight deactivated gas-fired generating plants, one coal-fired plant, TCCs interest in Oklaunion Power Station, a hydroelectric facility and TCCs interest in STP. TCC has entered into agreements to sell its 7.8% share of Oklaunion Power Station and its 25.2% share in STP and sold the remaining generation assets in July 2004. See Notes 6 and 10 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* and *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held For Sale and Assets Held and Used* , included in the 2004 Annual Reports, for more information on the disposition of TCC generation facilities.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC. OPCo is entitled to 100% of the power generated by the facility, and is responsible for the fuel and other costs of the facility through 2005. After 2005, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the facility, and both parties will generally be responsible for the fuel and other costs of the facility.

Certain Power Agreements

AEGCo *:* Since its formation in 1982, AEGCos business has consisted of the ownership and financing of its 50% interest in Unit 1 of the Rockport Plant and, since 1989, leasing of its 50% interest in Unit 2 of the Rockport Plant. The operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M and KPCo pursuant to unit power agreements, which have been approved by the FERC.

The I&M Power Agreement provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M). When added to amounts received by AEGCo from any other sources, such amounts will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement was extended in November 2004 for an additional 18 years and now expires in December 2022.

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities; (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant; (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements); and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The capital funds agreement will terminate after all AEGCo Obligations have been paid in full.

OVEC: AEP, CSPCo and several unaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. In April 2004, AEP agreed to sell a portion of its shares in OVEC (.73% of OVEC) to Louisville Gas and Electric Company. The sale is expected to close in the first quarter of 2005. Following the sale, the aggregate equity participation of AEP and CSPCo in OVEC will be 43.47%. Until September 1, 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are now entitled to receive and obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their power participation ratios. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 42.1%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Inter-Company Power Agreement (ICPA), which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms on March 12, 2006. An Amended and Restated ICPA has been unanimously approved and executed by the sponsoring companies and OVEC to extend the term of the ICPA for an additional 20 years to March 13, 2026. The aggregate power participation ratio of the AEP entities in the Amended and Restated ICPA is 43.47%. The AEP-affiliated owners of OVEC and the other owners are evaluating the need for environmental investments related to their ownership interests, which may be material.

Buckeye: Transmission service agreements between Buckeye, AEP and other transmission owners provide for the transmission and delivery of power generated by Buckeye at the Cardinal Station. These transmission agreements were made pursuant to the applicable open access transmission tariffs (OATT) of AEP and others. On October 1, 2004, AEP joined PJM, and the Buckeye transmission service over the AEP system was transferred under the PJM OATT. Buckeye is entitled under the Cardinal Station

Agreement to receive, and is obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on January 23, 2003, was recorded at 1,409,726 kilowatts.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

AEPs public utility subsidiaries (other than AEGCo) own and operate transmission and distribution lines and other facilities to deliver electric power. See *Item 2Properties* for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEPs public utility subsidiaries in their service territories. These sales are made at rates established and approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See *RegulationRates* . The FERC regulates and approves the rates for wholesale transmission transactions. See *RegulationFERC* . As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEPs public utility subsidiaries (other than AEGCo) hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see *Competition* .

AEP Transmission Pool

Transmission Equalization Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system and are parties to the Transmission Equalization Agreement, dated April 1, 1984, as amended (TEA), defining how they share the costs and benefits associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 KV and above) and certain facilities operated at lower voltages (138 KV and above). The TEA has been approved by the FERC. Sharing under the TEA is based upon each companys member-load ratio. The member-load ratio is calculated monthly by dividing such companys highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. As of December 31, 2004, the member-load ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	6,298	30.7
CSPCo	3,623	17.6
I&M	4,051	19.8
KPCo	1,478	7.2
OPCo	5,059	24.7

The following table shows the net (credits) or charges allocated among the parties to the TEA during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
APCo	$ (13,400)	$ 0	$ (500)
CSPCo	42,200	38,200	37,700
I&M	(36,100)	(39,800)	(40,800)
KPCo	(5,400)	(5,600)	(6,100)
OPCo	12,700	7,200	9,700

Transmission Coordination Agreement: PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone public utility subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone public utility subsidiaries have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the AEP OATT on their behalf. The TCA also provides for the allocation among the west zone public utility subsidiaries of revenues collected for transmission and ancillary services provided under the AEP OATT.

The following table shows the net (credits) or charges allocated among the parties to the TCA during the years ended December 31, 2002, 2003 and 2004:

	2002	2003	2004
		(in thousands)	
PSO	$ 4,200	$ 4,200	$ 8,100
SWEPCo	5,000	5,000	13,800
TCC	(3,600)	(3,600)	(12,200)
TNC	(5,600)	(5,600)	(9,700)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEPs public utility subsidiaries and other System companies also provide transmission services for non-affiliated companies. See *Regional Transmission Organizations.* Transmission of electric power by AEPs public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission: AEPs System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEPs east and west zone public utility subsidiaries. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TEA and the TCA. The System Transmission Integration Agreement contains two service schedules that govern:

The allocation of transmission costs and revenues and

The allocation of third-party transmission costs and revenues and System dispatch costs.

The System Transmission Integration Agreement contemplates that additional service schedules may be added as circumstances warrant.

Regional Transmission Organizations

On April 24, 1996, the FERC issued orders 888 and 889. These orders require each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utilitys own uses of its transmission system. The orders also require utilities to functionally unbundle their services, by requiring them to use their own tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a *pro-forma* tariff that reflects the Commissions views on the minimum non-price terms and conditions for non-discriminatory transmission service. In addition, the orders require all transmitting utilities to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct that prohibit utilities system operators from providing non-public transmission information to the utilitys merchant energy employees. The orders also allow a utility to seek recovery of certain prudently incurred stranded costs that result from unbundled transmission service.

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals.

As a condition of FERCs approval in 2000 of AEPs merger with CSW, AEP was required to transfer functional control of its transmission facilities to one or more RTOs. In May 2002, AEP announced an agreement with PJM to pursue terms for its east zone public utility subsidiaries to participate in PJM, a FERC-approved RTO. The AEP East Companies integrated into PJM on October 1, 2004.

SWEPCo and PSO currently intend to transfer functional control of their transmission assets to SPP subject to receipt of appropriate regulatory approvals. In February 2004, the FERC conditionally approved SPP as an RTO. In October 2004, the FERC issued an order granting RTO status to SPP subject to certain filings. The Arkansas Public Service Commission and LPSC have required filings related to SWEPCos transfer of functional control of transmission facilities to an RTO. The remaining west zone public utility subsidiaries (TCC and TNC) are members of ERCOT.

See Note 4 to the consolidated financial statements, entitled *Rate Matters* , included in the 2004 Annual Reports and *Managements Financial Discussion and Analysis of Results of Operations* under the heading entitled *RTO Formation* for a discussion of public utility subsidiary participation in RTOs.

Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs revenue distribution protocols.

AEP and several other utilities in the Combined Footprint filed a proposal for new rates to become effective December 1, 2004. In November 2004, FERC eliminated the T&O rates and replaced the rates temporarily through March 2006 with a seams elimination cost adjustment (SECA) fees. AEPs East zone public utility subsidiaries received approximately $1 96 million of T&O rate revenues for the twelve months ended September 30, 2004, the last twelve months prior to joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA fees was $171 million. Effective April 2006, all transmission costs that would otherwise be defrayed by T&O rates in the Combined Footprint will be subject to recovery from native load customers of AEPs East zone public utility subsidiaries. At this time, management is unable to predict whether any resultant increase in rates applicable to AEPs internal load will be recoverable on a timely basis from state retail customers. Unless new replacement rates compensate AEP for its lost revenues and any increase in AEPs East zone public utility subsidiaries transmission expenses from these new rates are fully recovered in retail rates on a timely basis, future results of operations, cash flows and financial condition will be adversely affected. See *Managements Financial Discussion and Analysis of Results of Operations* under the heading entitled *FERC Order on Regional Through and Out Rates* for more information.

REGULATION

General

Except for retail generation sales in Ohio, Virginia and the ERCOT area of Texas, AEPs public utility subsidiaries retail rates and certain other matters are subject to traditional regulation by the state utility commissions. While still regulated, retail sales in Michigan are now made at unbundled rates. See *Electric Restructuring and Customer Choice Legislation* and *Rates* . AEPs subsidiaries are also subject to regulation by the FERC under the FPA. I&M and TCC are subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant and STP, respectively. AEP and certain of its subsidiaries are also subject to the broad regulatory provisions of PUHCA administered by the SEC.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utilitys cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (i) a utilitys revenues and expenses during a defined test period and (ii) such utilitys level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time as part of a transition to customer choice of generation suppliers, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

The rates of AEPs public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In Ohio, Virginia and the ERCOT area of Texas, rates are transitioning from bundled cost-based rates for electric service to unbundled cost-based rates for transmission and distribution service on the one hand, and market pricing for and/or customer choice of generation on the other. In Ohio, the PUCO has approved the rate stabilization plans filed by OPCo and CSPCo which, among other things, address retail generation service rates through December 31, 2008. In Virginia, APCOs base rates are capped, subject to certain adjustments, at their mid-1999 levels until December 31, 2010, or sooner if the VSCC finds that a competitive market for generation exists in Virginia.

Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utilitys rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes. While the historical framework remains in a portion of AEPs service territory, recovery of increased fuel costs through a fuel adjustment clause is no longer provided for in Ohio. Fuel recovery is also limited in the ERCOT area of Texas, but because AEP sold MECPL and MEWTU, there is little impact on AEP of fuel recovery procedures related to service in ERCOT.

The following state-by-state analysis summarizes the regulatory environment of each jurisdiction in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction.

Indiana *:* I&M provides retail electric service in Indiana at bundled rates approved by the IURC. While rates are set on a cost-of-service basis, utilities may also generally seek to adjust fuel clause rates quarterly. I&Ms base rates were capped through December 31, 2004. Its fuel recovery rate was capped through February 29, 2004. On September 22, 2004, the IURC issued an order extending the interim fuel factor through March 2005, subject to true-up upon resolution of the (previously filed but unexecuted) corporate separation plan. The status of additional base and fuel clause rate caps, subject to certain conditions, is presently under discussion with the parties to a proposed settlement agreement relating to AEPs corporate separation issues.

Ohio *:* CSPCo and OPCo each operates as a functionally separated utility and provides default retail electric service to customers at unbundled rates pursuant to the Ohio Act through December 31, 2005. The PUCO approved the rate stabilization plan filed by CSPCo and OPCo (which, among other things, addresses default retail generation service rates from January 1, 2006 through December 31, 2008). Retail generation rates would be determined consistent with the rate stabilization plan until December 31, 2008. CSPCo and OPCo are and will continue to provide distribution services to retail customers at rates approved by the PUCO. These rates will be frozen (with certain exceptions) from their levels as of December 31, 2005 through December 31, 2008. Transmission services will continue to be provided at rates established by the FERC. See Note 6 to the consolidated financial statements, entitled *Customer Choice and Industry Restructuring* , included in the 2004 Annual Reports, for more information.

Oklahoma *:* PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSOs rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is adjusted quarterly and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new quarterly factors are established. See Note 4 to the consolidated financial statements, entitled *Rate Matters* , included in the 2004 Annual Reports, for information regarding current rate proceedings.

Texas: The Texas Act requires the legal separation of generation-related assets from transmission and distribution assets. TCC and TNC currently operate on a functionally separated basis. In January 2002, TCC and TNC transferred all their retail customers in the ERCOT area of Texas to MECPL, MEWTU and AEP Commercial and Industrial REP (an AEP affiliate). TNCs retail SPP customers were ultimately transferred to Mutual Energy SWEPCo L.P. (an AEP affiliate). TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. See Note 4 to the consolidated financial statements, entitled *Rate Matters* , included in the 2004 Annual Reports, for information on current rate proceedings.

In May 2003, the PUCT delayed competition in the SPP area of Texas until at least January 1, 2007. As such, SWEPCos Texas operations continue to operate and to be regulated as a traditional bundled utility with both base and fuel rates.

Virginia: APCo provides unbundled retail electric service in Virginia. APCos unbundled generation, transmission (which reflect FERC approved transmission rates) and distribution rates as well as its functional separation plan were approved by the VSCC in December 2001.

The Virginia Act, which was amended in 2004, capped APCOs base rates at their mid-1999 levels until the end of the transition period (now December 31, 2010), or sooner if the VSCC finds that a competitive market for generation exists in Virginia. The Virginia Act permits APCo to seek two changes to its capped rates as follows: one prior to July 1, 2007, and one between July 1, 2007 and December 31, 2010. In addition, as a result of the 2004 amendments, APCo is entitled to annual rate changes to recover the incremental costs it incurs on and after July 1, 2004 for transmission and distribution reliability and compliance with state or federal environmental laws or regulations. The Virginia Act also allows adjustments to fuel rates during the transition period and continues to permit utilities to recover their actual fuel costs, the fuel component of their purchased power costs and certain capacity charges. APCo recovers its generation capacity charges through capped base rates.

West Virginia *:* APCo and Wheeling Power Company provide retail electric service at bundled rates approved by the WVPSC. A plan to introduce customer choice was approved by the West Virginia Legislature in its 2000 legislative session. However, implementation of that plan was placed on hold pending necessary changes to the states tax laws in a subsequent session. Those changes have not been made. Management currently believes that implementation of the plan is unlikely.

While West Virginia generally allows for timely recovery of fuel costs, the most recent rate proceeding for both APCo and WPCo resulted in the suspension of their operative fuel clause mechanisms (though they continue to recover a fixed level of fuel costs through bundled rates). APCo and Wheeling Power Company are currently unable to change the current level of fuel cost recovery, though this ability could be reinstated in a future proceeding.

Other Jurisdictions *:* The public utility subsidiaries of AEP also provide service at regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan.

The following table illustrates the current rate regulation status of the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	Status of Base Rates for Power Supply	Status of Base Rates for Energy Delivery	Fuel Clause Rates(7) Status	System Sales Profits Shared with Ratepayers	Percentage of AEP System Retail Revenues(1)
Ohio	Frozen through 2005 (2)	Distribution frozen through 2008 (2)	None	Not applicable	32%
Oklahoma	Not capped or frozen	Not capped or frozen	Active	Yes	13%
Texas ERCOT	See footnote 3	Not capped or frozen	Not applicable	Not applicable	8%(3)
Texas SPP	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%(3)
Indiana	Extension of freeze is pending(4)	Extension of freeze is pending (4)	Extension of cap is pending (4)	No	11%
Virginia	Capped until as late as 12/31/10 (5)	Capped until as late as 12/31/10 (5)	Active	No	9%
West Virginia	Not capped or frozen	Not capped or frozen	Suspended (6)	Yes, but suspended	9%
Louisiana	Capped until 6/15/05	Capped until 6/15/05	Active	Yes, above base levels	4%
Kentucky	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%
Arkansas	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	3%
Michigan	Not capped or frozen	Not capped or frozen	Active	Yes, in some areas	2%
Tennessee	Not capped or frozen	Not capped or frozen	Active	No	1%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2004.

(2) The PUCO has approved the rate stabilization plan filed by CSPCo and OPCo that begins after the market development period and extends through December 31, 2008 during which OPCos retail generation rates will increase 7% annually and CSPCos retail generation rates will increase 3% annually. Distribution rates are frozen, with certain exceptions, through December 31, 2008.

(3) Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.

(4) Capped base rates pursuant to a 1999 settlement with base rate freeze extended pursuant to merger stipulation. The status of additional base and fuel clause rate caps, subject to certain conditions, is presently under discussion and there is an issue as to whether the freeze and cap extend through 2007 under an existing corporate separation stipulation agreement . The interim fuel clause rate cap expires in April 2005.

(5) Legislation passed in 2004 capped base rates until December 31, 2010 and expanded the rate change opportunities to one full rate case (including generation, transmission and distribution) between July 1, 2004 and June 30, 2007 and one additional full rate case between July 1, 2007 and December 31, 2010. The new law also permits APCo to recover, on a timely basis, incremental costs incurred on and after July 1, 2004 for transmission and distribution reliability purposes and to comply with state and federal environmental laws and regulations.

(6) Expanded net energy clause suspended in West Virginia pursuant to a 1999 rate case stipulation, but subject to change in a future proceeding.

(7) Includes, where applicable, fuel and fuel portion of purchased power.

FERC

Under the FPA, FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require AEP to provide open access transmission service at FERC-approved rates. FERC also regulates unbundled transmission service to retail customers.

Under the FPA, the FERC regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. AEP has market-rate authority from FERC, under which most of its wholesale marketing activity takes place. In November 2001, the FERC issued an order in connection with its triennial review of AEPs market based pricing authority requiring (i) certain actions by AEP in connection with its sales and purchases within its control area and (ii) posting of information related to generation facility status on AEPs website. AEP appealed that order, and the FERC issued an order delaying the effective date of the order. This was done in connection with the FERCs adoption of a new test called supply management assessment (SMA).

In April 2004, the FERC issued two orders concerning utilities ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a pivotal supplier test which determines if the market load can be fully served by alternative suppliers and a market share test which compares the amount of surplus generation at the time of the applicants minimum load. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order and directing AEP and two unaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERCs current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, as amended on September 16, 2004 and November 19, 2004, AEP submitted its generation market power screens in compliance with the FERCs orders. The analysis focused on the three major areas in which AEP serves load and owns generation resources -- ECAR, SPP and ERCOT, and the first tier control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its first tier markets. In its three home control areas, AEP passed the pivotal supplier test. As part of PJM, AEP also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area.

In a December 17, 2004 Order, FERC affirmed our conclusions that we passed both market power screen tests in all areas except SPP. Because AEP did not pass the market share screen in SPP, FERC initiated a proceeding under Section 206 of the FPA in which AEP is rebuttably presumed to possess market power in SPP. Consequently, our revenues from sales within our control area of the SPP at market based rates after March 6, 2005 will be collected subject to refund to the extent that prices are ultimately found not to be just and reasonable. In February 2005 AEP filed with the FERC revisions to its market-based rate tariffs that cap the rates of wholesale power that AEP delivers within its control area of the SPP. We are unable to predict the timing or impact of any further action by the FERC.

ELECTRIC RESTRUCTURING AND CUSTOMER CHOICE LEGISLATION

Certain states in AEPs service area have adopted restructuring or customer choice legislation. In general, this legislation provides for a transition from bundled cost-based rate regulated electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier. At a minimum, this legislation allows retail customers to select alternative generation suppliers. Electric restructuring and/or customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and the ERCOT area of Texas. Electric restructuring in the SPP area of Texas has been delayed by the PUCT until at least 2007. AEPs public utility subsidiaries operate in both the ERCOT and SPP areas of Texas.

Implementation of legislation enacted in West Virginia to allow retail customers to choose their electricity supplier is unlikely. In order for West Virginias choice plan to become effective, tax legislation must be passed to preserve pre-legislation levels of funding for state and local governments. Because such legislation has not been passed and because legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities, management currently believes that implementation of the plan is unlikely. In February 2003, Arkansas repealed its restructuring legislation.

See Note 5 to the consolidated financial statements, entitled *Effects of Regulation* , included in the 2004 Annual Reports, for a discussion of the effect of restructuring and customer choice legislation on accounting procedures. See Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* for additional information.

Michigan Customer Choice

Customer choice commenced for I&Ms Michigan customers on January 1, 2002. Rates for retail electric service for I&Ms Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2004, none of I&Ms Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&Ms Michigan service territory.

Ohio Restructuring

The Ohio Act requires vertically integrated electric utility companies that offer competitive retail electric service in Ohio to separate their generating functions from their transmission and distribution functions. Following the market development period (which will terminate no later than December 31, 2005), retail customers will receive distribution and, where applicable, transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. CSPCo and OPCo filed a rate stabilization plan with the PUCO that, among other things, addresses default generation service rates from January 1, 2006 through December 31, 2008. See *RegulationFERC* for a discussion of FERC regulation of transmission rates and *RegulationRatesOhio* for a discussion of the impact of restructuring on distribution rates. The PUCO approved the rate stabilization plan filed by CSPCo and OPCo, with certain modifications. The Commission authorized CSPCo and OPCo to remain functionally separated through the end of that three-year period.

Texas Restructuring

Signed into law in June of 1999, the Texas Act substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition for all customers. Among other things, the Texas Act:

- gave Texas customers the opportunity to choose their REP beginning January 1, 2002 (delayed until at least 2007 in the SPP portion of Texas),

- required each utility to legally separate into a REP, a power generation company, and a transmission and distribution utility, and

- required that REPs provide electricity at generally unregulated rates, except that the prices that may be charged to residential and small commercial customers by REPs affiliated with a utility within the affiliated utilitys service area are set by the PUCT, at the PTB, until certain conditions in the Texas Act are met.

The Texas Act provides each affected utility an opportunity to recover its generation related regulatory assets and stranded costs resulting from the legal separation of the transmission and distribution utility from the generation facilities and the related introduction of retail electric competition. Regulatory assets consist of the Texas jurisdictional amount of generation-related regulatory assets and liabilities in the audited financial statements as of December 31, 1998. Stranded costs consist of the positive excess of the net regulated book value of generation assets (as of December 31, 2001) over the market value of those assets, taking specified factors into account, as ultimately determined in a PUCT true-up proceeding.

For a discussion of (i) regulatory assets and stranded costs subject to recovery by TCC and (ii) rate adjustments made after implementation of restructuring to allow recovery of certain costs by or with respect to TCC and TNC, see *Texas Regulatory Asset and Stranded Cost Recovery and Post-Restructuring Wires Charges* and Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring.*

Virginia Restructuring

In April 2004, the Governor of Virginia signed legislation that extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

Texas Regulatory Assets And Stranded Cost Recovery And Post-Restructuring Wires Charges

TCC may recover generation-related regulatory assets and plant-related stranded costs. Regulatory assets consist of the Texas jurisdictional amount of generation-related regulatory assets and liabilities in the audited financial statements as of December 31, 1998. Plant-related stranded costs consist of the positive excess of the net regulated book value of generation assets (as of December 31, 2001) over the market value of those assets, taking specified factors into account. The Texas Act allows alternative methods of valuation to determine the fair market value of generation assets, including outright sale, full and partial stock valuation and asset exchanges, and also, for nuclear generation assets, the excess cost over market (ECOM) model. Carrying costs on stranded costs are also allowed to be recovered beginning January 1, 2002.

TCCs true-up proceedings will determine the amount and recovery of:

net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),

a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCTs ECOM model for 2002 and 2003 (wholesale capacity auction true-up),

excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),

final approved deferred fuel balance, and

net carrying costs on the above true-up amounts.

The PUCT adopted a rule in 2003 regarding the timing of the true-up proceedings scheduling TCCs filing 60 days after the completion of the sale of TCCs generation assets. Due to regulatory and contractual delays in the sale of its generating assets, TCC has not yet filed its true-up request.

TCCs net true-up regulatory assets (liabilities) recorded at December 31, 2004 is set forth in the following table.

TCCs net true-up regulatory assets (liabilities)

	(in millions)
Stranded Generation Plant Costs	$897
Net Generation-related Regulatory Asset	249
Unrefunded Excess Earnings	(10)
Net Stranded Generation Costs	1,136
Carrying Costs on Stranded Generation Plant Costs	225
Net Stranded Generation Costs Designated for Securitization	1,361
Wholesale Capacity Auction True-up	483
Carrying Costs on Wholesale Capacity Auction True-up	77

Retail Clawback	(61)
Deferred Over-recovered Fuel Balance	(212)
Net Other Recoverable True-up Amounts	287
Total Recorded Net True-up Regulatory Asset (Liability)	$1,648

For a more complete discussion of recovery of regulatory assets and stranded costs in Texas, see Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* , included in the 2004 Annual Reports.

The Texas Act further permits utilities to establish a special purpose entity to issue securitization bonds for the recovery of generation-related regulatory assets and, after the true-up proceeding, the amount of plant-related stranded costs and remaining generation-related regulatory assets not previously securitized. Securitization bonds allow for regulatory assets and plant-related stranded costs to be refinanced with recovery of the bond principal and financing costs ensured through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds. Any plant-related stranded costs or generation-related regulatory assets not recovered through the sale of securitization bonds may be recovered through a separate non-bypassable competitive transition charge to transmission and distribution customers.

For a discussion of recovery of regulatory assets and stranded costs in Ohio and Virginia, see Note 6 to the consolidated financial statements entitled *Customer Choice and Industry Restructuring* , included in the 2004 Annual Reports.

COMPETITION

The public utility subsidiaries of AEP, like the electric industry generally, face increasing competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEPs public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy in recent years have led to increased price competition for industrial customers in the United States, including those served by the AEP System. Some of these industrial customers have requested price reductions from their suppliers of electric power. In addition, industrial customers that are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options pursuant to tariffs filed with the various state commissions. Occasionally, these rates are first negotiated, and then filed with the state commissions. The public utility subsidiaries believe that they are unlikely to be materially adversely affected by this competition.

SEASONALITY

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEPs facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder.

Unusually mild weather in the future could diminish AEPs results of operations and may impact its financial condition.

INVESTMENTS

GAS OPERATIONS

During 2004 we sold our interests in Louisiana Intrastate Gas and Jefferson Island Storage & Hub. In January 2005, we sold a 98% controlling interest in HPL and related assets. We currently retain a 2% ownership interest in HPL and will provide certain transitional services to the buyer. See Notes 10 and 19 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used* and *Subsequent Events (unaudited)* , respectively, included in the 2004 Annual Reports for more information. Before these sales, our gas marketing operations had been significantly curtailed. As a result of these sales, management anticipates that our gas marketing operations will be limited to managing our obligations with respect to the gas transactions entered into before to these sales.

UK OPERATIONS

Through subsidiaries, AEP operated and owned 4,000 MW of power generation facilities in the UK. These assets and related commodities contracts were sold to Scottish and Southern Energy plc in the third quarter of 2004. AEP also sold its 50 percent interest in South Coast Power Limited to co-owner Scottish Power Generation Limited in the third quarter of 2004. See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used,* included in the 2004 Annual Reports.

OTHER

General

Through certain subsidiaries, AEP conducts business operations other than those included in other segments in which it uses and manages a portfolio of energy-related assets. Consistent with its business strategy, AEP intends to dispose of some of these non-core assets. The assets currently used and managed include:

791 MW of domestic and 605 MW of international power generation facilities (of which its ownership is approximately 551 MW and 302 MW, respectively);

Undeveloped and formerly operated coal properties and related facilities; and

Barge, rail and other fuel transportation related assets.

These operations include the following activities:

Entering into long-term transactions to buy or sell capacity, energy, and ancillary services of electric generating facilities at various locations in North America.

Holding various properties, coal reserves and royalty interests and reclaiming formerly operated mining properties in Colorado, Indiana, Kentucky, Louisiana, Ohio, Texas, Utah and West Virginia; and

Through MEMCO Barge Line Inc., transporting coal and dry bulk commodities, primarily on the Ohio, Illinois, and Lower Mississippi rivers for AEP, as well as unaffiliated customers. Through certain subsidiaries, AEP owns or leases 7,065 railcars, 2,230 barges, 53 towboats and a coal handling terminal with 20 million tons of annual capacity.

AEP has in the past three years written down the value of certain of these investments. See *Managements Financial Discussion and Analysis of Results of Operations* and Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used,* included in the 2004 Annual Reports.

Dow Chemical Cogeneration Facility

Pursuant to an agreement with Dow, AEP constructed a 900 MW cogeneration facility at Dows chemical facility in Plaquemine, Louisiana that achieved commercial operation status on March 18, 2004. AEPs subsidiary, OPCo, has been taking 100% of the facilitys capacity and energy over Dows requirements and contracted to sell the power from this facility for twenty years to Tractebel. The power supply contract with Tractebel is in dispute and the power from this plant is currently sold on the market. See Notes 7 and 10 to the consolidated financial statements, entitled *Commitments and Contingencies* and *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used* , respectively, included in the 2004 Annual Reports, for more information.

ITEM 2. PROPERTIES

<u>GENERATION FACILITIES</u>

GENERAL

At December 31, 2004, the AEP System owned (or leased where indicated) generating plants with net power capabilities (east zone public utility subsidiaries-winter rating; west zone public utility subsidiaries-summer rating) shown in the following table:

Company	S tations	Coal MW	Natural Gas MW	Hydro MW	Nuclear MW	Lignite MW	Oil MW	Total MW
AEGCo	1 (a)	1,300						1,300
APCo	16 (b)	5,073		798				5,871
CSPCo	5 (e)	2,595						2,595
I&M	9 (a)	2,295		11	2,143			4,449
KPCo	1	1,060						1,060

OPCo	8 (b)(f)	8,472		48				8,520
PSO	8 (c)	1,018	3,139				25	4,182
SWEPCo	9	1,848	1,797			842		4,487
TCC	2 (c)(d)(g)	54			630			684
TNC	11 (c)	377	999 (h)				10	1,386
Totals:	65	24,092	5,935	857	2,773	842	35	34,534

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.

(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.

(c) PSO, TCC and TNC, along with two unaffiliated companies, jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.

(d) Reflects TCCs interest in STP.

(e) CSPCo owns generating units in common with CG&E and DP&L. Its ownership interest of 1,330 MW is reflected in this table.

(f) The scrubber facilities at the General James M. Gavin Plant are leased. OPCo may terminate the lease as early as 2010.

(g) See *Item 1 Utility Operations Electric Generation Deactivation and Disposition of Generation Facilities* for a discussion of TCCs planned disposition of all its generation facilities.

(h) TNCs gas fired generation is deactivated.

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities, both foreign and domestic. Information concerning these facilities at December 31, 2004 is listed below.

Facility	Fuel	Location	Capacity Total MW	Ownership Interest	Status
Desert Sky Wind Farm	Wind	Texas	161	100%	Exempt Wholesale Generator(1)
Sweeney	Natural gas	Texas	480	50%	Qualifying Facility(2)
Trent Wind Farm	Wind	Texas	150	100%	Exempt Wholesale Generator(1)
Total U.S.			791		
Bajio	Natural gas	Mexico	605	50%	Foreign Utility Company(1)
Total			1,396		

(1) As defined under PUHCA

(2) As defined under the Public Utility Regulatory Policies Act of 1978

See Note 10 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used*, included in the 2004 Annual Reports, for a discussion of AEPs planned use and/or disposition of independent power producer and foreign generation assets.

COOK NUCLEAR PLANT AND STP

The following table provides operating information relating to the Cook Plant and STP.

	Cook Plant		**STP (a)**	
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**
Year Placed in Operation	1975	1978	1988	1989
Year of Expiration of NRC License (b)	2014	2017	2027	2028
Nominal Net Electrical Rating in Kilowatts	1,036,000	1,107,000	1,250,600	1,250,600
Net Capacity Factors (e)				
2004	97.0%	81.6%	100.8%	93.7%
2003 (c)	73.5%	74.5%	62.0%	81.2%
2002	86.6%	80.5%	99.2%	75.0%
2001 (d)	87.3%	83.4%	94.4%	87.1%

(a) Reflects total plant. TCC has an ownership interest in STP of approximately 25.2%. TCC has entered into an agreement to sell this interest and the sale is expected to be completed in 2005.

(b) AEP has filed to extend the licenses at the Cook Plant.

(c) The capacity factors for both units of the Cook Plant were reduced in 2003 due to an unplanned maintenance outage to implement upgrades to the traveling water screens system following an alewife fish intrusion. The capacity factors for the STP units were reduced due to an unplanned outage for BMI repairs on Unit 1 and an unplanned outage for turbine repairs on Unit 2.

(d) The capacity factor for both units of the Cook Plant was significantly reduced in 2001 due to an unplanned dual maintenance outage in September 2001 to implement design changes that improved the performance of the essential service water system.

(e) Cook Plant 2004 Net Capacity Factor values reflect Nominal Net Electrical Rating in Kilowatts of 1,036,000 (Unit 1) and 1,107,000 (Unit 2). However, Cook Plant 2003 and earlier Net Capacity Factor values reflect previous Nominal Net Electrical Rating in Kilowatts of 1,020,000 (Unit 1) and 1,090,000 (Unit 2).

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. I&M and TCC may also incur costs and experience reduced output at Cook Plant and STP, respectively, because of the design criteria prevailing at the time of construction and the age of the plants systems and equipment. Nuclear industry-wide and Cook Plant and STP initiatives have contributed to slowing the growth of operating and maintenance costs at these plants. However, the ability of I&M and TCC to obtain adequate and timely recovery of costs associated with the Cook Plant and STP, respectively, including replacement power, any unamortized investment at the end of the useful life of the Cook Plant and STP (whether scheduled or premature), the carrying costs of that investment and retirement costs, is not assured. See *Item 1 Utility Operations Electric Generation Planned Deactivation and Planned Disposition of Generation Facilities* for a discussion of TCCs planned disposition of its interest in STP.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765 kV lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	**Circuit Miles of 765 kV Lines**
AEP System (a)	216,306 (b)	2,026
APCo	51,147	644
CSPCo (a)	14,030	
I&M	21,980	615
Kingsport Power Company	1,343	
KPCo	10,780	258
OPCo	30,627	509
PSO	21,100	

SWEPCo	20,455
TCC	29,571
TNC	13,578
Wheeling Power Company	1,696

(a) Includes 766 miles of 345 kV jointly owned lines.

(b) Includes 73 miles of transmission lines not identified with an operating company.

TITLES

The AEP Systems generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEPs public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. AEPs public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Recent legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

Substantially all the fixed physical properties and franchises of TNC, APCo, PSO, and SWEPCo, except for limited exceptions, are subject to the lien of the mortgage and deed of trust securing the first mortgage bonds of each such company.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Lawsin the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia, and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes, and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

GENERAL

The AEP System, with input from its state utility commissions, continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. Thus, System reinforcement plans are subject to change, particularly with the restructuring of the electric utility industry. AEP forecasts $2.7 billion of construction expenditures for 2005. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

PROPOSED TRANSMISSION FACILITIES

APCo is proceeding with its plan to build the Jacksons Ferry-Wyoming 765 ,000-volt transmission line. The WVPSC and the VSCC have issued certificates authorizing construction and operation of the line. On December 31, 2002, the U.S. Forest Service issued a final environmental impact statement and record of decision to allow the use of federal lands in the Jefferson National Forest for construction of a portion of the line. On May 11, 2004, the decision of the Forest Service was challenged by the Sierra Club in the United States District Court for the Western District of Virginia. APCo has intervened in that litigation . Construction of the line is underway and the project is scheduled to be completed by June 2006.

PROPOSED GENERATION FACILITY

In conjunction with an environmental impact study issued in August 2004, in the third quarter of 2004 we announced plans to construct a synthetic-gas-fired plant or plantsof approximately1,000 MW of capacity in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology. We estimate that this new plant or plants will costin the range of $1.7 billion. We have not determined a location for the plantor plants, but it or they will bein one of our eastern states, because of ready access to coal. We are currently performing site analysis and evaluation and at the same time working with state regulators and legislators to establish a framework for expedient recovery of this significant investment in new clean coal technology before final site selection. We have filed with PJM for transmission analysis of sites in Ohio, West Virginia and Kentucky.

Our significant planned environmental investments in emission control installations at existing coal-fired plants and our commitment to IGCC technology reinforce our belief that coal will be a lower-emission domestic energy source of the future and further signals our commitment to investing in clean, environmentally safe technology. For additional information regarding anticipated environmental expenditures, see *Managements Financial Discussion and Analysis of Results of Operations* under the heading entitled *The Current Air Quality Regulatory Framework* .

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2002, 2003 and 2004 and current estimates of 2005 construction expenditures, in each case including AFUDC, but excluding assets acquired under leases.

	2002 Actual	**2003 Actual**	**2004 Actual**	**2005 Estimate**
		(in thousands)		
AEP System (a)	$1,709,800	$1,358,400	$1,693,200	$2,732,400
AEGCo	5,300	22,200	15,800	19,900
APCo	276,500	288,800	452,200	696,700
CSPCo	136,800	136,300	149,800	193,900
I&M	159,400	184,600	176,800	322,800
KPCo	178,700	81,700	38,500	56,100
OPCo	354,800	249,700	345,500	765,600
PSO	89,400	86,800	82,300	126,200
SWEPCo	111,800	121,100	103,100	200,900
TCC	151,600	141,800	121,300	208,500
TNC	43,600	46,700	36,400	73,900

(a) Includes expenditures of other subsidiaries not shown. Amounts in 2002 and 2003 include construction expenditures related to entities classified in 2004 as discontinued operations. These amounts were $186,500,000 and $24,900,000, respectively. The figures reflect construction expenditures, not investments in subsidiary companies.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the Systems construction program.

See Note 7 to the consolidated financial statements entitled *Commitments and Contingencies*, incorporated by reference in Item 8, for further information with respect to the construction plans of AEP and its operating subsidiaries for the next year.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP, I&M, TCC and other AEP System companies. See Note 7 to the consolidated financial statements entitled *Commitments and Contingencies,* incorporated by reference in Item 8, for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 7 to the consolidated financial statements, entitled *Commitments and Contingencies* , incorporated by reference in Item 8.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE

OF SECURITY HOLDERS

AEP, APCo, I&M, OPCo, SWEPCo and TCC. None.

AEGCo, CSPCo, KPCo, PSO and TNC. Omitted pursuant to Instruction I(2)(c).

EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of March 1, 2005.

Name	Age	Office (a)
Michael G. Morris	58	Chairman of the Board, President and Chief Executive Officer of AEP and of AEPSC
Coulter R. Boyle III	56	Senior Vice President of AEP and Senior Vice President-Commercial Operations of AEPSC
Carl L. English	58	President-Utility Group of AEP and of AEPSC

Thomas M. Hagan	60	Executive Vice President-AEP Utilities-West of AEPSC
John B. Keane	58	Senior Vice President, General Counsel and Secretary of AEP and of AEPSC
Holly K. Koeppel	46	Executive Vice President-AEP Utilities-East of AEPSC
Robert P. Powers	51	Executive Vice President of AEP and Executive Vice President-Generation of AEPSC
Susan Tomasky	51	Executive Vice President and Chief Financial Officer of AEP and of AEPSC

(a) Before joining AEPSC in his current position in January 2004, Mr. Morris was Chairman of the Board, President and Chief Executive Officer of Northeast Utilities (1997-2003). Messrs. Boyle and Powers and Ms. Tomasky have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Before joining AEPSC in June 2000 as Senior Vice President-Governmental Affairs, Mr. Hagan was Senior Vice President-External Affairs of CSW (1996-2000). Before joining AEPSC in July 2000 as Vice President-New Ventures, Ms. Koeppel was Regional Vice President of Asia-Pacific Operations for Consolidated Natural Gas International (1996-2000). Messrs. Hagan and Powers, Ms. Koeppel and Ms. Tomasky became executive officers of AEP effective with their promotions to Executive Vice President on September 9, 2002, October 24, 2001, November 18, 2002 and January 26, 2000, respectively. As a result of AEPs realignment of its executive management team in July 2004, Messrs. Boyle and Keane became executive officers of AEP. Before joining AEPSC in his current position in July 2004, Mr. Keane was President of Bainbridge Crossing Advisors. Prior to that, he was Vice President-Administration for Northeast Utilities (1998-2002). Mr. English joined AEP as President-Utility Group and became an executive officer of AEP on August 1, 2004. Before joining AEPSC in his current position in August 2004, Mr. English was President and Chief Executive Officer of Consumers Energy gas division (1999-2004). All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of AEPSC, or both, as the case may be.

APCo, I&M, OPCo, SWEPCo and TCC. The names of the executive officers of APCo, I&M, OPCo, SWEPCo and TCC, the positions they hold with these companies, their ages as of March 1, 2005, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, I&M, OPCo, SWEPCo and TCC are elected annually to serve a one-year term.

Name	**Age**	**Position**	**Period**
Michael G. Morris (a)(b)	58	Chairman of the Board, President, Chief Executive Officer and Director of AEP	2004-Present
		Chairman of the Board, Chief Executive Officer and Director of AEPSC, APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Chairman of the Board, President and Chief Executive Officer of Northeast Utilities	1997-2003
Coulter R. Boyle III	56	Senior Vice President of AEP and Senior Vice President- Commercial Operations and Director of AEPSC	2004-Present
		Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President of AEPSC	2003-2004
		Vice President of AEPSC	1999-2003
Carl L. English (c)	58	President-Utility Group of AEP and President-Utility Group and Director of AEPSC	2004-Present
		Director and Vice President of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		President and Chief Executive Officer of Consumers Energy gas division	1999-2004
Thomas M. Hagan (d)	60	Executive Vice President-AEP Utilities-West and Director of AEPSC	2004-Present
		Vice Chairman of the Board, Vice President and Director of TCC and SWEPCo	2004-Present
		Vice President and Director of APCo, I&M and OPCo	2002-2004
		Executive Vice President of AEP	2004
		Executive Vice President-Shared Services of AEPSC	2002-2004
		Senior Vice President-Governmental Affairs of AEPSC	2000-2002
		Senior Vice President-External Affairs of CSW	1996-2000
John B. Keane (a)	58	Senior Vice President, General Counsel and Secretary of AEP and of AEPSC	2004-Present
		President of Bainbridge Crossing Advisors	2003-2004
		Vice President-Administration-Northeast Utilities	1998-2002
Holly K. Koeppel (e)	46	Executive Vice President-AEP Utilities-East and Director of AEPSC	2004-Present
		Vice Chairman of the Board, Vice President and Director of APCo, I&M and OPCo	2004-Present
		Executive Vice President of AEP	2004

		Executive Vice President-Commercial Operations of AEPSC	2002-2004
		Vice President-New Ventures	2000-2002
		Regional Vice President of Asia-Pacific Operations for Consolidated Natural Gas International	1996-2000
Robert P. Powers (a)	51	Executive Vice President of AEP	2004-Present
		Director-AEPSC	2001-Present
		Executive Vice President-Generation of AEPSC	2003-2004
		Director and Vice President of APCo, OPCo, SWEPCo and TCC	2001-Present
		Director of I&M	2001-Present
		Vice President of I&M	1998-Present
		Executive Vice President-Nuclear Generation and Technical Services of AEPSC	2001-2003
		Senior Vice President-Nuclear Operations of AEPSC	2000-2001
		Senior Vice President-Nuclear Generation and Director of AEPSC	1998-2000
Susan Tomasky (a)	51	Executive Vice President and Chief Financial Officer of AEP and of AEPSC	2004-Present
		Chief Financial Officer of AEP	2001-2004
		Director of AEPSC	1998-Present
		Vice President and Director of APCo, I&M, OPCo, SWEPCo and TCC	2000-Present
		Executive Vice President-Policy, Finance and Strategic Planning of AEPSC	2001-2004
		Executive Vice President-Legal, Policy and Corporate Communications of AEPSC	2000-2001
		Senior Vice President and General Counsel of AEPSC	1998-2001

(a) Messrs. Keane, Morris and Powers and Ms. Tomasky are directors of AEGCo, CSPCo, KPCo, PSO and TNC.

(b) Mr. Morris is a director of Cincinnati Bell, Inc. and The Hartford Financial Services Group, Inc.

(c) Mr. English is a director of CSPCo, KPCo, PSO and TNC.

(d) Mr. Hagan is a director of AEGCo, PSO and TNC.

(e) Ms. Koeppel is a director of CSPCo and KPCo.

APCo:

Name	Age	Position	Period
Dana E. Waldo	**53**	**President and Chief Operating Officer of APCo and Kingsport Power Company**	**2004-Present**
		President and Chief Executive Officer of West Virginia Roundtable	**1999-2004**
		Vice President of APCo	**1995-1999**

I&M:

Marsha P. Ryan	**54**	**President and Chief Operating Officer of I&M**	**2004-Present**
		Senior Vice President-Customer Operations of AEPSC	**2000-2004**
		State President-Ohio	**1996-2000**
		Vice President of APCo, I&M, SWEPCo and TCC	**2000-2004**
		Vice President of CSPCo and OPCo	**1996-2004**
OPCo:			
Kevin E. Walker	**42**	**President and Chief Operating Officer of CSPCo, OPCo and WPCo**	**2004-Present**
		Vice President of Consolidated Edison (New York)	**2001-2004**
		Vice President of Public Service of New Hampshire	**2000-2001**
SWEPCo:			
Nicholas K. Akins	**44**	**President and Chief Operating Officer of SWEPCo**	**2004-Present**
		Vice President of AEPSC	**2000-2004**
		Director of CSW	**1999-2000**
TCC:			
Charles R. Patton	**45**	**President and Chief Operating Officer of TCC**	**2004-Present**
		Vice President of Governmental and Environmental Affairs-Texas	**2002-2004**
		Vice President of State Governmental Affairs of AEPSC	**2000-2002**
		Director of Government Affairs	**1999-2000**

PART II

ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY ,

RELATED STOCKHOLDER MATTERS

AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP . The information required by this item is incorporated herein by reference to the material under *Common Stock and Dividend Information* in the 2004 Annual Report.

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2004 and 2003 are incorporated by reference to the material under *Statement of Retained Earnings* in the 2004 Annual Reports.

ITEM 6. SELECTED FINANCIAL DATA

AEGCo , **CSPCo, KPCo, PSO and TNC.** Omitted pursuant to Instruction I(2)(a).

AEP, APCo, I&M, OPCo, SWEPCo and TCC . The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2004 Annual Reports.

ITEM 7. MANAGEMENTS DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION

AND RESULTS OF OPERATION

AEGCo, CSPCo, KPCo, PSO and TNC . Omitted pursuant to Instruction I(2)(a). Managements narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Managements Financial Discussion and Analysis* in the 2004 Annual Reports.

AEP, APCo, I&M, OPCo, SWEPCo and TCC . The information required by this item is incorporated herein by reference to the material under *Managements Financial Discussion and Analysis* in the 2004 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE

DISCLOSURES ABOUT MARKET RISK

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC . The information required by this item is incorporated herein by reference to the material under *Managements Financial Discussion and Analysis* in the 2004 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS

AND SUPPLEMENTARY DATA

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH

ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2004, management, including the principal executive officer and principal financial officer of AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo TCC and TNC (collectively, the Registrants), evaluated the Registrants disclosure controls and procedures relating to the recording, processing, summarization and reporting of information in the Registrants periodic reports filed with the SEC. These disclosure controls and procedures have been designed to ensure that (a) material information relating to the Registrants is made known to the Registrants management, including these officers, by other employees of the Registrants and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SECs rules and forms. The Registrants disclosure controls and procedures can only provide reasonable, not absolute, assurance that the above objectives have been met.

As of December 31, 2004, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

AEPs East zone public utility subsidiaries integrated into PJM on October 1, 2004. In connection with this integration, AEP and these subsidiaries implemented or modified a number of business processes and controls to facilitate participation in, and resultant settlement within, the PJM market. Apart from this, there have been no significant changes in AEPs internal controls over financial reporting (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) during the fourth quarter of 2004 that have materially affected, or are reasonably likely to materially affect, AEPs internal controls over financial reporting.

Additional information required by this item of AEP, as an accelerated filer, is incorporated by reference to *Managements Report on Internal Controls over Financial Reporting,* included in the 2004 Annual Reports.

ITEM 9B. OTHER INFORMATION

AEPs East zone public utility subsidiaries integrated into PJM on October 1, 2004 pursuant to various agreements filed herewith as exhibits. As a result, PJM has assumed functional control of the transmission grid of AEPs East zone public utility subsidiaries.

The Human Resources Committee of AEPs Board of Directors (the Committee) has approved the performance metrics that will be used to determine the amount of the awards under AEPs Senior Officer Incentive Plan (the SOIP) for 2005 for AEPs executive officers. The performance metrics are based on safety performance, workforce development, strategic planning, and environmental stewardship. The overall funding level for all of AEP's incentive plans, including the SOIP, will be based on the extent to which AEPs earnings per share improves over the prior year and meets or exceeds the 2005 budget approved by AEPs Board of Directors. However, this overall funding level may be reduced at the discretion of the CEO or adjusted, either positively or negatively, at the discretion of the Committee.

The Committee also set the 2005 annual incentive award targets, expressed as a percentage of salary, under the SOIP for AEPs executive officers. Payouts of annual incentive awards are dependent on the level of achievement of the corporate financial and operational goals approved by the Committee and discussed above. Target annual incentive awards were set at 100 percent of salary for the CEO, 65 percent of salary for the CFO, and either 50 or 60 percent of salary for the remaining executive officers of AEP.

Individual awards recommendations for executive officers, other than for Mr. Morris, are determined on a discretionary basis by Mr. Morris and are subject to the approval of the Committee. The individual award recommendation for Mr. Morris is determined on a discretionary basis by the Committee and is subject to the approval of the independent members of AEPs Board of Directors.

On January 25, 2005, the independent members of the AEP Board of Directors set the 2005 annual base salary for Michael G. Morris at $1,150,000. On January 25, 2005, the Committee set the 2005 annual base salaries for Susan Tomasky at $500,000; Thomas M. Hagan at $440,000; Holly K. Koeppel at $440,000; and Robert P. Powers at $450,000. Each of these individuals is an AEP named executive officer for 2004. For further information regarding executive compensation, see Item 11. Executive Compensation herein.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS

OF THE REGISTRANTS

AEGCo , **CSPCo, KPCo, PSO and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP . The information required by this item is incorporated herein by reference to the material under *Nominees for Director* and *Section 16(a) Beneficial Ownership Reporting Compliance* of the definitive proxy statement of AEP for the 2005 annual meeting of shareholders, to be filed within 120 days after December 31, 2004. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

APCo and OPCo . The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

I&M, SWEPCo and TCC . The names of the directors and executive officers of I&M, SWEPCo and TCC, the positions they hold with I&M, SWEPCo and TCC, their ages as of March 1, 2005, and a brief account of their business experience during the past five years appear below or under the caption *Executive Officers of the Registrants* in Part I of this report.

I&M:

Name	**Age**	**Position**	**Period**
K. G. Boyd	53	Director	1997-Present
		Vice President-Fort Wayne Region Distribution Operations	2000-Present
		Indiana Region Manager	1997-2000
John E. Ehler	48	Director	2001-Present
		Manager of Distribution Systems-Fort Wayne District	2000-Present
		Region Operations Manager	1997-2000
Patrick C. Hale	50	Director	2003-Present
		Plant Manager, Rockport Plant	2003-Present
		Energy Production Manager, Rockport Plant	2001-2003
		Energy Production Manager, Mountaineer Plant (APCo)	1997-2001
David L. Lahrman	53	Director and Manager, Region Support	2001-Present
		Fort Wayne District Manager	1997-2001
Marc E. Lewis	50	Director	2001-Present
		Assistant General Counsel of AEPSC	2001-Present
		Senior Counsel of AEPSC	2000-2001
		Senior Attorney of AEPSC	1994-2000
Susanne M. Moorman Rowe	55	Director and General Manager, Corporate Communications	2004-Present
		Director and General Manager, Community Services	2000-2004
		Manager, Customer Services Operations	1997-2000
Venita McCellon-Allen(a)	45	Director and Senior Vice President-Shared Services of AEPSC	2004-Present
		Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President-Human Resources for Baylor Health Care System	2000-2004
		Senior Vice President-Customer Services and Corporate Development of CSW	1996-2000
John R. Sampson	52	Director and Vice President	1999-Present
		Indiana State President	2000-2004
		Indiana & Michigan State President	1999-2000
		Site Vice President, Cook Nuclear Plant	1998-1999

SWEPCo and TCC:

Name	**Age**	**Position**	**Period**
Venita McCellon-Allen (a)	45	Director and Senior Vice President-Shared Services of AEPSC	2004-Present
		Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		Senior Vice President-Human Resources for Baylor Health Care Systems	2000-2004

		Senior Vice President-Customer Services and Corporate Development of CSW	1996-2000
Stephen P. Smith (b)	44	Senior Vice President and Treasurer of AEP	2004-Present
		Senior Vice President-Corporate Accounting, Planning & Strategy, Treasurer and Director of AEPSC	2003-Present
		Treasurer of APCo, I&M, OPCo, SWEPCo and TCC	2003-Present
		Vice President and Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-Present
		President and Chief Operating Officer-Corporate Services for NiSource	1999-2003

(a) Ms. McCellon-Allen is a director of CSPCo, KPCo, PSO and TNC.

(b) Mr. Smith is a director of AEGCo, CSPCo, KPCo, PSO and TNC.

ITEM 11. EXECUTIVE COMPENSATION

AEGCo , **CSPCo, KPCo, PSO and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP . The information required by this item is incorporated herein by reference to the material under *Directors Compensation and Stock Ownership Guidelines, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

APCo and OPCo . The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

I&M, SWEPCo and TCC . The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of APCo for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN

BENEFICIAL OWNERS AND MANAGEMENT

AEGCo , **CSPCo, KPCo, PSO and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP . The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* of the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

APCo and OPCo . The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

I&M. All 1,400,000 outstanding shares of Common Stock, no par value, of I&M are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of I&M generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2005, by each director and nominee of I&M and each of the executive officers of I&M named in the summary compensation table, and by all directors and executive officers of I&M as a group. It is based on information provided to I&M by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of I&M. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	**Shares (a)**	**Stock Units (b)**	**Total**
Karl G. Boyd	12,805	253	13,058
John E. Ehler			
Carl L. English		30,632	30,632
Patrick C. Hale	3,342		3,342
Holly K. Koeppel	61,612	380	61,992
David L. Lahrman	276		276
Marc E. Lewis	9,859		9,859
Venita McCellon-Allen		10,103	10,103
Suzanne M. Moorman Rowe	42		42
Michael G. Morris	360,587 (e)		360,587
Robert P. Powers	200,957 (c)	1,345	202,302
Marsha P. Ryan	32,565	1,047	33,612
John R. Sampson	18,634		18,634
Susan Tomasky	240,334 (c)	6,744	247,078
All Directors and Executive Officers	1,026,244 (c)(d)	50,504	1,076,748

	AEP Retirement Savings Plan
Name	**(Share Equivalents)**
Karl G. Boyd	100
John E. Ehler	
Carl L. English	
Patrick C. Hale	76
Holly K. Koeppel	246
David L. Lahrman	276
Marc E. Lewis	1,410
Venita McCellon-Allen	
Marsha P. Ryan	6,189
Suzanne M. Moorman Rowe	42
Michael G. Morris	
Robert P. Powers	658
John R. Sampson	934
Susan Tomasky	2,668

All Directors and Executive Officers	12,598

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Boyd, 12,700; Mr. Hale, 3,266; Ms. Koeppel, 61,366; Mr. Lewis, 8,449; Mr. Powers, 200,299; Ms. Ryan, 26,366; Mr. Sampson, 17,700; and Ms. Tomasky, 237,666.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.

(b) This column includes amounts deferred in stock units and held under AEPs various director and officer benefit plans.

(c) Does not include, for Ms. Tomasky and Mr. Powers, 85,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky and Mr. Powers share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.

(d) Represents less than 1.5% of the total number of shares outstanding.

(e) Consists of restricted shares with different vesting schedules and accrued dividends.

SWEPCo. All 7,536,640 outstanding shares of Common Stock, $18 par value, of SWEPCo are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of SWEPCo generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2005, by each director and nominee of SWEPCo and each of the executive officers of SWEPCo named in the summary compensation table, and by all directors and executive officers of SWEPCo as a group. It is based on information provided to SWEPCo by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of SWEPCo. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	**Shares (a)**	**Stock Units (b)**	**Total**
Nicholas K. Akins	13,877		13,877
Carl L. English		30,632	30,632
Thomas M. Hagan	144,529	155	144,684
John B. Keane		15,316	15,316
Holly K. Koeppel	61,612	380	61,992
Venita McCellon-Allen		10,103	10,103
Michael G. Morris	360,587 (e)		360,587
Robert P. Powers	200,957 (c)	1,345	202,302
Stephen P. Smith	16,500		16,500
Susan Tomasky	240,334 (c)	6,744	247,078

All Directors and Executive Officers	1,123, 627 (c)(d)	64,675	1,188,302

Name	AEP Retirement Savings Plan (Share Equivalents)
Nicholas K. Akins	1,177
Carl L. English	
Thomas M. Hagan	4,537
John B. Keane	
Holly K. Koeppel	246
Venita McCellon-Allen	
Michael G. Morris	
Robert P. Powers	658
Stephen P. Smith	
Susan Tomasky	2,668
All Directors and Executive Officers	9,286

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Akins, 12,700; Mr. Hagan, 129,499; Ms. Koeppel, 61,367; Mr. Morris, 49,666; Mr. Powers, 200,299; Mr. Smith, 16,500; and Ms. Tomasky, 237,666.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.

(b) This column includes amounts deferred in stock units and held under AEPs various director and officer benefit plans.

(c) Does not include, for Ms. Tomasky and Mr. Powers, 85,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky and Mr. Powers share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.

(d) Represents less than 1.5% of the total number of shares outstanding.

(e) Consists of restricted shares with different vesting schedules and accrued dividends.

TCC. All 2,211,678 outstanding shares of Common Stock, $25 par value, of TCC are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of TCC generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2005, by each director and nominee of TCC and each of the executive officers of TCC named in the summary compensation table, and by all directors and executive officers of TCC as a group. It is based on information provided to TCC by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of TCC. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	**Shares (a)**	**Stock Units (b)**	**Total**
Carl L. English	30,632		30,632
Thomas M. Hagan	144,529	155	144,684
John B. Keane		15,316	15,316
Holly K. Koeppel	61,612	380	61,992
Venita McCellon-Allen		10,103	10,103
Michael G. Morris	360,587 (e)		360,587
Charles R. Patton	7,400		7,400
Robert P. Powers	200,957 (c)	1,345	202,302
Stephen P. Smith	16,500		16,500
Susan Tomasky	240,334 (c)	6,744	247,078
All Directors and Executive Officers	1,147,782 (c)(d)	34,043	1,181,825

Name	**AEP Retirement Savings Plan (Share Equivalents)**
Carl L. English	
Thomas M. Hagan	4,537
John B. Keane	
Holly K. Koeppel	246
Venita McCellon-Allen	
Michael G. Morris	
Charles R. Patton	
Robert P. Powers	658
Stephen P. Smith	
Susan Tomasky	2,668
All Directors and Executive Officers	8,109

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Hagan, 129,499; Ms. Koeppel, 61,367; Mr. Morris, 49,666; Mr. Patton, 7,400; Mr. Powers, 200,299; Mr. Smith, 16,500; and Ms. Tomasky, 237,666.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.

(b) This column includes amounts deferred in stock units and held under AEPs various director and officer benefit plans.

(c) Does not include, for Ms. Tomasky and Mr. Powers, 85,231 shares in the American Electric Power System Educational Trust Fund over which Ms. Tomasky and Mr. Powers share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.

(d) Represents less than 1.5% of the total number of shares outstanding.

(e) Consists of restricted shares with different vesting schedules and accrued dividends.

EQUITY COMPENSATION PLAN INFORMATION

Information required by this item is incorporated by reference from the discussion under the heading *Equity Compensation Plan Information* in our proxy statement for the 2005 Annual Meeting of Shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

AEP, AEGCo , **APCo** , **CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC:** None.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP . The information required by this item is incorporated herein by reference to the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

APCo and OPCo . The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2005 annual meeting of stockholders, to be filed within 120 days after December 31, 2004.

AEGCo , **CSPCo, I&M, KPCo, PSO, SWEPCo, TCC and TNC.**

Each of the above is wholly-owned subsidiaries of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies annual financial statements for the years ended December 31, 2003 and 2004, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the definitive proxy statement of AEP for the 2005 annual meeting of shareholders to be filed within 120 days after December 31, 2004.

	AEGCo		**CSPCo**		**I&M**	
	2004	2003	2004	2003	2004	2003
Audit Fees						

Financial Statement Audits	$164,303		$608,935		$ 679,061	
Sarbanes-Oxley 404	112,341		518,610		490,537	
Audit Fees - Other	19,530		57,660		49,290	
Audit Fees Subtotal	296,174	$136,100	1,185,205	$385,000	1,218,888	$ 366,900
Audit-Related Fees	0	0	5,000	0	184,000	0
Tax Fees	67,539	1,000	888,188	349,000	1,136,796	26,000
TOTAL	$363,713	$137,100	$2,078,393	$734,000	$ 2,539,684	$ 392,900

	KPCo		**PSO**		**SWEPCo**	
	2004	2003	2004	2003	2004	2003
Audit Fees						
Financial Statement Audits	$413,013		$357,053		$ 411,970	
Sarbanes-Oxley 404	284,581		273,793		318,007	
Audit Fees - Other	36,270		24,180		27,900	
Audit Fees Subtotal	733,864	$289,000	655,026	$187,300	757,877	$ 212,900
Audit-Related Fees	0	0			10,000	0
Tax Fees	81,412	8,000	438,845	35,000	567,665	89,000
TOTAL	$815,276	$297,000	$1,093,871	$222,300	$ 1,335,542	$ 301,900

	TCC		**TNC**	
	2004	2003	2004	2003
Audit Fees				
Financial Statement Audits	$446,899		$ 159,950	
Sarbanes-Oxley 404	357,257		188,080	
Audit Fees - Other	46,500		26,040	
Audit Fees Subtotal	850,656	$ 511,000	374,070	$ 188,900
Audit-Related Fees	21,500		8,325	
Tax Fees	896,577	89,000	235,477	54,000
TOTAL	$1,768,733	$ 600,000	$ 617,872	$ 242,900

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as a part of this report:

1. Financial Statements:
The following financial statements have been incorporated herein by reference pursuant to Item 8.
AEGCo:
Statements of Income for the years ended December 31, 2004, 2003 and 2002; Statements of Retained Earnings for the years ended December 31, 2004, 2003 and 2002; Balance Sheets as of December 31, 2004 and 2003; Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.
AEP and Subsidiary Companies:
Reports of Independent Registered Public Accounting Firm; Managements Report on Internal Control over Financial Reporting; Consolidated Statements of Operations for the years ended December 31, 2004, 2003 and 2002; Consolidated Balance Sheets as of December 31, 2004 and 2003; Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Consolidated Statements of Common Shareholders Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries at December 31, 2004 and 2003; Schedule of Consolidated Long-term Debt of Subsidiaries at December 31, 2004 and 2003; Notes to Consolidated Financial Statements.
APCo, I&M, SWEPCo and TCC:
Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002; Consolidated Statements of Changes in Common Shareholders Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Consolidated Balance Sheets as of December 31, 2004 and 2003; Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Preferred Stock as of December 31, 2004 and 2003; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.
CSPCo:
Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002; Consolidated Statements of Changes in Common Shareholders Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Consolidated Balance Sheets as of December 31, 2004 and 2003; Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2004 and 2003; notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.
KPCo:
Statements of Income for the years ended December 31, 2004, 2003 and 2002; Statements of Changes in Common Shareholders Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Balance Sheets as of December 31, 2004 and 2003; Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.
PSO and TNC:
Statements of Income (or Statements of Operations) for the years ended December 31, 2004, 2003 and 2002; Statements of Common Shareholders Equity and Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002; Balance Sheets as of December 31, 2004 and 2003; Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002; Schedules of Preferred Stock as of December 31, 2004 and 2003; Schedule of Long-term Debt as of December 31, 2004 and 2003; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.
2. Financial Statement Schedules:
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Report of Independent Registered Public Accounting Firm
3. Exhibits:
Exhibits for AEGCo , AEP , APCo , CSPCo , I&M , KPCo , OPCo , PSO , SWEPCo, TCC and TNC are listed in the Exhibit Index beginning on page E-1 and are incorporated herein 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.

American Electric Power Company, Inc.

By: /s/ SUSAN TOMASKY
(Susan Tomasky, Executive Vice President and Chief Financial Officer)

Date: March 1, 2005

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 and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
*Michael G. Morris	Chairman of the Board, President, Chief Executive Officer And Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ Susan Tomasky **(Susan Tomasky)**	Executive Vice President and Chief Financial Officer	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
* E. R. Brooks		
* Donald M. Carlton		
* John P. Desbarres		
* Robert W. Fri		
* William R. Howell		
* Lester A. Hudson, Jr.		
* Leonard J. Kujawa		
*Lionel L. Nowell, III		
*Richard L. Sandor		
* Donald G. Smith		
* Kathryn D. Sullivan		

*By: /s/ Susan Tomasky March 1, 2005

(Susan Tomasky, Attorney-in-Fact)

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Generating Company

By:	/s/ Susan Tomasky

(Susan Tomasky, Vice President
and Chief Financial Officer)

Date: March 1, 2005

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 and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	**Title**	**Date**
(i) Principal Executive Officer:		
*Michael G. Morris	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ Susan Tomasky **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
* THOMAS M. HAGAN		
* JOHN B. KEANE		
*ROBERT P. POWERS		
*STEPHEN P. SMITH		

*By: /s/ Susan Tomasky March 1, 2005

(Susan Tomasky, Attorney-in-Fact)

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Texas Central Company

AEP Texas North Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

E y : /s/ Susan Tomasky

(Susan Tomasky, Vice President and Chief Financial Officer)

Date: March 1, 2005

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 and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	**Title**	**Date**
(i) Principal Executive Officer:		
*Michael G. Morris	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ Susan Tomasky **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*Carl L. English		
*thomas M. Hagan		
*John B. Keane		
*Venita McCellon-Allen		

*Robert P. Powers
*Stephen P. Smith

*By: /s/ Susan Tomasky March 1, 2005

(Susan Tomasky, Attorney-in-Fact)

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Appalachian Power Company

Columbus Southern Power Company
Kentucky Power Company
Ohio Power Company

E
y
: /s/ Susan Tomasky

(Susan Tomasky, Vice President and Chief Financial Officer)

Date: March 1, 2005

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 and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	**Title**	**Date**
(i) Principal Executive Officer:		
*Michael G. Morris	Chairman of the Board, Chief Executive Officer and Director	March 1, 2005
(ii) Principal Financial Officer:		
/s/ Susan Tomasky **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*Carl L. English		
*John B. Keane		
*Holly K. Koeppel		
*Venita McCellon-Allen		

*Robert P. Powers
*Stephen P. Smith

*By: /s/ Susan Tomasky March 1, 2005

(Susan Tomasky, Attorney-in-Fact)

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Indiana Michigan Power Company

By: /s/ Susan Tomasky

(Susan Tomasky, Vice President
and Chief Financial Officer)

Date: March 1, 2005

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 and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
*Michael G. Morris	Chairman of the Board, Chief Executive Officer and Director	March1, 2005
(ii) Principal Financial Officer:		
/s/ Susan Tomasky **(Susan Tomasky)**	Vice President, Chief Financial Officer and Director	March 1, 2005
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	March 1, 2005
(iv) A Majority of the Directors:		
*K. G. Boyd		
*John E. Ehler		
*Carl L. English		
*Patrick C. Hale		
*Holly Keller Koeppel		
*David L. Lahrman		

*Marc E. Lewis
*Venita McCellon-Allen
*Susanne M. Moorman Rowe
*Robert P. Powers
*John R. Sampson

*By: /s/ Susan Tomasky March 1, 2005

(Susan Tomasky, Attorney-in-Fact)

INDEX TO FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the Company) as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, managements assessment of the effectiveness of the Companys internal control over financial reporting as of December 31, 2004, and the effectiveness of the Companys internal control over financial reporting as of December 31, 2004, and have issued our reports thereon dated February 28, 2005 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2002, 2003 and 2004); such financial statements and reports are included in your 2004 Annual Report and are incorporated herein by reference. Our audits also included the financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Companys management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the corresponding basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche, LLP

Columbus, Ohio

February 28, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the financial statements of the AEP Texas Central Company and subsidiary, AEP Texas North Company, Appalachian Power Company and subsidiaries, Columbus Southern Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Kentucky Power Company, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively, the Companies) as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, and have issued our reports thereon dated February 28, 2005 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2002, 2003 and 2004); such financial statements and reports are included in your 2004 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche, LLP

Columbus, Ohio

February 28, 2005

INDEX TO FINANCIAL STATEMENT SCHEDULES

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 123,685	$ 39,766	$ 7,989	$ 94,265	$ 77,175
Year Ended December 31, 2003	107,578	55,087	7,234	46,214	123,685
Year Ended December 31, 2002	68,429	87,044	11,767	59,662	107,578

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 1,710	$ 3,493	$ -	$ 1,710	$ 3,493
Year Ended December 31, 2003	346	1,712	-	348	1,710
Year Ended December 31, 2002	186	162	1	3	346

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

AEP TEXAS NORTH COMPANY

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 175	$ 787	$ -	$ 175	$ 787
Year Ended December 31, 2003	5,041	123	-	4,989	175
Year Ended December 31, 2002	196	4,846	17	18	5,041

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 2,085	$ 3,059	$ 4,201	$ 3,784	$ 5,561
Year Ended December 31, 2003	13,439	4,708	433	16,495	2,085
Year Ended December 31, 2002	1,877	3,937	12,367	4,742	13,439

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 531	$ 577	$ 187	$ 621	$ 674
Year Ended December 31, 2003	634	96	-	199	531
Year Ended December 31, 2002	745	(100)	-	11	634

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 531	$ 195	$ 90	$ 629	$ 187
Year Ended December 31, 2003	578	37	-	84	531
Year Ended December 31, 2002	741	(161)	-	2	578

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

KENTUCKY POWER COMPANY

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C	Column D	Column E
		Additions		

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 736	$ 43	$ 27	$ 772	$ 34
Year Ended December 31, 2003	192	8	912	376	736
Year Ended December 31, 2002	264	(68)	-	4	192

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

OHIO POWER COMPANY CONSOLIDATED

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 789	$ 122	$ 89	$ 907	$ 93
Year Ended December 31, 2003	909	42	18	180	789
Year Ended December 31, 2002	1,379	(457)	-	13	909

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

PUBLIC SERVICE COMPANY OF OKLAHOMA

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		

Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 37	$ 21	$ 55	$ 37	$ 76
Year Ended December 31, 2003	84	37	-	84	37
Year Ended December 31, 2002	44	7	33	-	84
(a) Recoveries on accounts previously written off.					
(b) Uncollectible accounts written off.					

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	**Column B**	**Column C**		**Column D**	**Column E**
		Additions			
Description	**Balance at Beginning of Period**	**Charged to Costs and Expenses**	**Charged to Other Accounts (a)**	**Deductions (b)**	**Balance at End of Period**
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2004	$ 2,093	$ (2,079)	$ 134	$ 103	$ 45
Year Ended December 31, 2003	2,128	103	-	138	2,093
Year Ended December 31, 2002	89	2,036	4	1	2,128
(a) Recoveries on accounts previously written off.					
(b) Uncollectible accounts written off.					

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits (Ex) not identified as previously filed are filed herewith. Exhibits, designated with a dagger (), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form pursuant to Item 14(c) of this report.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	REGISTRANT: AEGCo File No. 0-18135	
3(a)	Articles of Incorporation of AEGCo.	Registration Statement on Form 10 for the Common Shares of AEGCo, Ex 3(a).
3(b)	Copy of the Code of Regulations of AEGCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
10(a)	Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP.	Registration Statement No. 33-32752, Ex 28(a).
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B).
10(b)(2)	Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KPCo.	Registration Statement No. 33-32752, Ex 28(b)(2).
10(c)	Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); 1993 Form 10-K, Ex 10(c)(1-6)(B).
*13	Copy of those portions of the AEGCo 2004 Annual Report, which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: AEP File No. 1-3525	
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated January 13, 1999.	1998 Form 10-K, Ex 3(c).
3(b)	By-Laws of AEP, as amended through December 15, 2003	2003 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c); Registration Statement No. 333-105532, Ex 4(d)(e)(f).
4(b)	Forward Purchase Contract Agreement, dated as of June 11, 2002, between AEP and The Bank of New York, as Forward Purchase Contract Agent	2002 Form 10-K, Ex 4(c).
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); 1990 Form 10-K, Ex 10(a)(3).

10(b)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K; Ex 10(b) 1988 Form 10-K, Ex 10(b)(2).
10(d)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(d).
*10(e)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(e)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(e)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(f)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); **AEGCO** 1993 Form 10-K, Ex 10(c)(1-6)(B); **I&M** 1993 Form 10-K, Ex 10(e)(1-6)(B).
10(g)	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested)	**OPCo** 1994 Form 10-K, Ex 10(l)(2).
10(h)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l)
10(i)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation	1997 Form 10-K, Ex 10(f).
10(i)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger	Form 8-K, Ex 10, dated December 15, 1999.
10(j)	AEP Accident Coverage Insurance Plan for directors.	1985 Form 10-K, Ex 10(g)
10(k)(1)	AEP Deferred Compensation and Stock Plan for Non-Employee Directors, as amended December 10, 2003	2003 Form 10-K, Ex 10(k)(1)
10(k)(2)	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended December 10, 2003.	2003 Form 10-K, Ex 10(k)(2).
10(l)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	2000 Form 10-K, Ex 10(j)(1)(A)
10(l)(1)(B)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
10(l)(1)(C)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(1)(1)(c)
10(l)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of September 1, 2004 (Non-Qualified).	2003 Form 10-K, Ex 10(l)(2). Form 8-K, Ex 99.1, dated September 1, 2004,
10(l)(3)	Service Corporation Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3).
10(m)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1).
10(m)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s)
10(m)(3)	Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.	2002 Form 10-K; Ex 10(m)(3)(A)
10(m)(4)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K; Ex 10(m)(4)
10(m)(5)	Letter Agreement dated June 4, 2004 between AEPSC and Carl English	Form 10-Q, Ex 10(b), September 30, 2004

10(n)	AEP System Senior Officer Annual Incentive Compensation Plan.	1996 Form 10-K, Ex 10(i)(1)
10(o)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
10(o)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(o)(2)
10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.	2003 Form 10-K, Ex 10(q)(1).
10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
10(r)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(s)
10(s)	AEP Change In Control Agreement effective January 1, 2005.	Form 8-K, Ex 10.1, dated January 10, 2005
10(t)(1)	AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.	2003 Form 10-K, Ex 10(u).
10(t)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System 2000 Long-Term Incentive Plan, as amended	Form 10-Q, Ex. 10(c), September 30, 2004
10(u)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	**CSW** 1998 Form 10-K, Ex 18, File No. 1-1443,
10(u)(2)	Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.	2003 Form 10-K, Ex 10(v)(3).
10(u)(3)	Central and South West Corporation Executive Deferred Savings Plan as amended and restated effective as of January 1, 1997.	**CSW** 1998 Form 10-K, Ex 24, File No. 1-1443.
*10(v)	Schedule of Non-Employee Directors Annual Compensation	
*10(w)	Base Salaries for Named Executive Officers	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the AEP 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: APCo File No. 1-3457	
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d).
3(b)	By-Laws of APCo, amended as of October 24, 2001.	2001 Form 10-K, Ex 3(e).

4(a)	Mortgage and Deed of Trust, dated as of December 1, 1940, between APCo and Bankers Trust Company and R. Gregory Page, as Trustees, as amended and supplemented.	Registration Statement No. 2-7289, Ex 7(b); Registration Statement No. 2-19884, Ex 2(1) Registration Statement No. 2-24453, Ex 2(n); Registration Statement No. 2-60015, Ex 2(b)(2-10)(12)(14-28); Registration Statement No. 2-64102, Ex 2(b)(29); Registration Statement No. 2-66457, Ex (2)(b)(30-31); Registration Statement No. 2-69217, Ex 2(b)(32); Registration Statement No. 2-86237, Ex 4(b); Registration Statement No. 33-11723, Ex 4(b); Registration Statement No. 33-17003, Ex 4(a)(ii), Registration Statement No. 33-30964, Ex 4(b); Registration Statement No. 33-40720, Ex 4(b); Registration Statement No. 33-45219, Ex 4(b); Registration Statement No. 33-46128, Ex 4(b)(c); Registration Statement No. 33-53410, Ex 4(b); Registration Statement No. 33-59834, Ex 4(b); Registration Statement No. 33-50229, Ex 4(b)(c); Registration Statement No. 33-58431, Ex 4(b)(c)(d)(e); Registration Statement No. 333-01049, Ex 4(b)(c); Registration Statement No. 333-20305, Ex 4(b)(c); 1996 Form 10-K, Ex 4(b); 1998 Form 10-K, Ex 4(b).
4(b)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a); Registration Statement No. 333-49071, Ex 4(b); Registration Statement No. 333-84061, Ex 4(b)(c); 1999 Form 10-K, Ex 4(c); Registration Statement No. 333-81402, Ex 4(b)(c)(d); Registration Statement No. 333-100451, Ex 4(b); 2002 Form 10-K, Ex 4(c).
4(c)	Company Order and Officers Certificate to The Bank of New York, dated July 1, 2004, establishing terms of Floating Rate Notes, Series C, due 2007.	Form 8-K, Ex 4(a), dated July 1, 2004.

10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); 1989 Form 10-K, Ex 10(a)(1)(F); 1992 Form 10-K, Ex 10(a)(1)(B)].
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); 1992 Form 10-K, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); **AEP** 1990 Form 10-K, File No. 1-3525, Ex 10(a)(3).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	**AEP** 1985 Form 10-K, Ex 10(b); **AEP** 1988 Form 10-K, Ex 10(b)(2).
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	**AEP** 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	**AEP** 1997 Form 10-K, Ex 10(f), File No. 1-3525.
10(f)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
10(g)	AEP System Senior Officer Annual Incentive Compensation Plan	**AEP** 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
10(h)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	**AEP** 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
10(h)(1)(B)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(h)(1)(B).
10(h)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of September 1, 2004 (Non-Qualified).	AEP Form 8-K, Ex 99.1, dated September 1, 2004
10(h)(3)	Umbrella Trust for Executives.	**AEP** 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
10(i)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(i)(1).
10(i)(2)	Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.	**AEP** 2000 Form 10-K, Ex 10(s), File No. 1-3525.
10(i)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K; Ex 10(i)(3).
10(i)(4)	Letter Agreement dated June 4, 2004 between AEPSC and Carl English	**AEP** Form 10-Q, Ex 10(b), September 30, 2004

10(j)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	**AEP** Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525.
10(j)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(j)(2).
10(k)	AEP Change In Control Agreement, effective January 1, 2005.	**AEP** Form 8-K, Ex 10.1 dated January 10, 2005, File No. 1-3525.
10(l)(1)	AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.	2003 Form 10-K, Ex 10(m).
10(l)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System 2000 Long-Term Incentive Plan, as amended	**AEP** Form 10-Q, Ex. 10(c), dated November 5, 2004.
10(m)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	**CSW** 1998 Form 10-K, Ex 18, File No. 1-1443.
10(m)(2)	Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.	2003 Form 10-K, Ex 10(n)(3).
10(n)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.	2003 Form 10-K, Ex 10(o)(1).
10(o)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K; Ex 10(p).
10(p)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(q).
*10(q)	Base Salaries for Named Executive Officers	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of APCo	**AEP** 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: CSPCo File No. 1-2680	
3(a)	Composite of Amended Articles of Incorporation of CSPCo, dated May 19, 1994.	1994 Form 10-K, Ex 3(c).
3(b)	Code of Regulations and By-Laws of CSPCo.	1987 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d); 1998 Form 10-K, Ex 4(c)(d).
4(b)	First Supplemental Indenture between CSPCo and Deutsche Bank Trust Company Americas, as Trustee, dated November 25, 2003, establishing terms of 4.40% Senior Notes, Series E, due 2010.	2003 Form 10-K, Ex 4(c).
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(d).
4(d)	First Supplemental Indenture, dated as of February 1, 2003, between CSPCo and Bank One, N.A., AS trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series C, due 2013.	2003 Form 10-K, Ex 4(e).

4(e)	Second Supplemental Indenture, dated as of February 1, 2003, between CSPCo and Bank One establishing the terms of 6.60% Senior Notes, Series B, due 2033 and 6.60% Senior Notes, Series D, due 2033.	2003 Form 10-K, Ex 4(f).
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(B); **APCo** 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; **APCo** 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457.
10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); **APCo** 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457.
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); **AEP** 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC as agent, as amended.	**AEP** 1985 Form 10-K, Ex 10(b), File No. 1-3525; **AEP** 1988 Form 10-K, Ex 10(b)(2) File No. 1-3525.
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	**AEP** 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	**AEP** 1997 Form 10-K, Ex 10(f), File No. 1-3525.
10(f)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the CSPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of CSPCo	**AEP** 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	

*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: I&M File No. 1-3570	
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997	1996 Form 10-K, Ex 3(c).
3(b)	By-Laws of I&M, amended as of November 28, 2001.	2001 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c); Registration Statement No. 333-58656, Ex 4(b)(c); Registration Statement No. 333-108975, Ex 4(b)(c)(d)].
4(b)	Company Order and Officers Certificate, dated November 10, 2004, establishing terms of 5.05% Senior Notes, Series F, due 2014.	Form 8-K, Ex. 4(a), dated November 16, 2004
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); **APCo** 1989 Form 10-K, File No. 1-3457, Ex 10(a)(1)(F); **APCo** 1992 Form 10-K, File No. 1-3457, Ex 10(a)(1)(B).
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); **APCo** Form 10-K, File No. 1-3457, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended	Registration Statement No. 2-60015, Ex 5(e).
10(a)(4)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); **APCo** 1992 Form 10-K, File No. 1-3457, Ex 10(a)(2)(B).
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); **AEP** 1990 Form 10-K, File No. 1-3525, Ex 10(a)(3).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	**AEP** 1985 Form 10-K, File No. 1-3525, Ex 10(b); **AEP** 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	**AEP** 1996 Form 10-K, File No. 1-3525, Ex 10(l).

10(f)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); 1993 Form 10-K, Ex 10(e)(1-6)(B).
10(g)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	**AEP** 1997 Form 10-K, File No. 1-3525, Ex 10(f).
10(g)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger	Form 8-K, Ex 10, December 15, 1999.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of I&M.	**AEP** 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: KPCo File No. 1-6858	
3(a)	Restated Articles of Incorporation of KPCo.	1991 Form 10-K, Ex 3(a).
3(b)	By-Laws of KPCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between KPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-75785, Ex 4(a)(b)(c)(d); Registration Statement No. 333-87216, Ex 4(e)(f); 2002 Form 10-K, Ex 4(c)(d)(e).
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); **AEP** 1990 Form 10-K, File No. 1-3525, Ex 10(a)(3).
10(b)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	**AEP** 1985 Form 10-K, File No. 1-3525, Ex 10(b); **AEP** 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
*10(c)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(c)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(c)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(d)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	**AEP** 1996 Form 10-K, File No. 1-3525, Ex 10(l).
10(e)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation	**AEP** 1997 Form 10-K, File No. 1-3525, Ex 10(f).
10(e)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
*12	Statement re: Computation of Ratios.	

*13	Copy of those portions of the KPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: OPCo File No.1-6543	
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002.
3(b)	Code of Regulations of OPCo.	1990 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c); Registration Statement No. 333-106242, Ex 4(b)(c)(d); Registration Statement No. 333-75783, Ex 4(b)(c).
4(b)	First Supplemental Indenture between OPCo and Deutsche Bank Trust Company Americas, as Trustee, dated July 11, 2003, establishing terms of 4.85% Senior Notes, Series H, due 2014.	2003 Form 10-K, Ex 4(c).
4(c)	Second Supplemental Indenture between OPCo and Deutsche Bank Trust Company Americas, as Trustee, dated July 11, 2003, establishing terms of 6.375% Senior Notes, Series I, due 2033.	2003 Form 10-K, Ex 4(d).
4(d)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(e).
4(e)	First Supplemental Indenture, dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series D, due 2013 and 5.50% Senior Notes, Series F, due 2013.	2003 Form 10-K, Ex 4(f).
4(f)	Second Supplemental Indenture, dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee, establishing the terms of 6.60% Senior Notes, Series E, due 2033 and 6.60% Senior Notes, Series G, due 2033.	2003 Form 10-K, Ex 4(g).
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); **APCo** Form 10-K, File No. 1-3457, Ex 10(a)(1)(F); **APCo** Form 10-K, File No. 1-3457, Ex 10(a)(1)(B).
10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); **APCo** Form 10-K, File No. 1-3457, Ex 10(a)(2)(B).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e).

10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); **AEP** 1990 Form 10-K, File 1-3525, Ex 10(a)(3).
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.	**AEP** 1985 Form 10-K, File No. 1-3525, Ex 10(b); **AEP** 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
*10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
*10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	
*10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	**AEP** 1996 Form 10-K, File No. 1-3525, Ex 10(l).
10(f)(1)	Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	1993 Form 10-K, Ex 10(f). 2003 Form 10-K, Ex 10(e)
10(f)(2)	Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	Form 10-Q, Ex 10(a), September 30, 2004.
10(g)	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested).	1994 Form 10-K, Ex 10(l)(2).
10(h)(1)	Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation.	**AEP** 1997 Form 10-K, File No. 1-3525, Ex 10(f).
10(h)(2)	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger.	Form 8-K, Ex 10, dated December 15, 1999.
10(i)	AEP System Senior Officer Annual Incentive Compensation Plan.	**AEP** 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
10(j)(1)(A)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.	**AEP** 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
10(j)(1)(B)	First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.	2002 Form 10-K; Ex 10(i)(1)(B)
10(j)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of September 1, 2004 (Non-Qualified).	**AEP** Form 8-K, Ex 99.1, dated September 1, 2004.
10(j)(3)	Umbrella Trust for Executives.	**AEP** 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
10(k)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(j)(1).
10(k)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	**AEP** 2000 Form 10-K, Ex 10(s), File No. 1-3525.
10(k)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(j)(3).
10(k)(4)	Letter Agreement dated June 4, 2004 between AEPSC and Carl English	**AEP** Form 10-Q, Ex 10(b), September 30, 2004, File No. 1-3525,
10(l)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	**AEP** Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525,.

10(l)(2)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K; Ex 10(k)(2).
10(m)	AEP Change In Control Agreement, effective January 1, 2005.	**AEP** Form 8-K, Ex 10.1, dated January 10, 2005, File No. 1-3525.
10(n)(1)	AEP System 2000 Long-Term Incentive Plan, as amended December 10, 2003.	2003 Form 10-K, Ex 10(n).
10(n)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System 2000 Long-Term Incentive Plan, as amended	**AEP** Form 10-Q, Ex. 10(c), dated November 5, 2004.
10(o)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	1998 Form 10-K, File No. 1-1443, Ex 18.
10(o)(2)	Certified AEP Utilities, Inc. (formerly CSW) Board Resolutions of July 16, 1996.	2003 Form 10-K, Ex 10(o)(3).
10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2003.	2003 Form 10-K, Ex 10(p)(1).
10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(q).
10(r)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K, Ex 10(r).
*10(s)	Base Salaries for Named Executive Officers	
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of OPCo.	**AEP** 2004 Form 10-K, File No. 1-3525, Ex 21
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: PSO File No. 0-343	
3(a)	Restated Certificate of Incorporation of PSO.	**CSW** 1996 Form U5S, File No. 1-1443, Ex B-3.1.
3(b)	By-Laws of PSO (amended as of June 28, 2000).	2002 Form 10-K, Ex 3(b).

4(a)	Indenture, dated July 1, 1945, between and Liberty Bank and Trust Company of Tulsa, National Association, as Trustee, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.03; Registration Statement No. 2-64432, Ex 2.02; Registration Statement No. 2-65871, Ex 2.02; Form U-1 No. 70-6822, Ex 2; Form U-1 No. 70-7234, Ex 3; Registration Statement No. 33-48650, Ex 4(b); Registration Statement No. 33-49143, Ex 4(c); Registration Statement No. 33-49575, Ex 4(b); 1993 Form 10-K, Ex 4(b); Form 8-K, Ex 4.01; dated March 4, 1996. Form 8-K, Ex 4.02, dated March 4, 1996; Form 8-K, Ex 4.03, dated March 4, 1996.
4(b)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Exs 4(a)(b); 2002 Form 10-K; Ex 4(c).
4(c)	Third Supplemental Indenture, dated as of September 15, 2003, between PSO and The Bank of New York, as Trustee, establishing terms of the 4.85% Senior Notes, Series C, due 2010.	2003 Form 10-K, Ex 4(d).
4(d)	Fourth Supplemental Indenture, dated as of June 7, 2004 between PSO and The Bank of New York, as Trustee, establishing terms of the 4.70% Senior Notes, Series D, due 2009	Form 8-K, Ex 4(a), dated June 7, 2004
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of PSO.	**AEP** 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: SWEPCo File No. 1-3146	
3(a)	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation.	Form 10-Q, Ex 3.4, March 31, 1997.
3(b)	By-Laws of SWEPCo (amended as of April 27, 2000).	Form 10-Q, Ex 3.3, March 31, 2000.

4(a)	Indenture, dated February 1, 1940, between SWEPCo and Continental Bank, National Association and M. J. Kruger, as Trustees, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.04; Registration Statement No. 2-61943, Ex 2.02; Registration Statement No. 2-66033, Ex 2.02; Registration Statement No. 2-71126, Ex 2.02; Registration Statement No. 2-77165, Ex 2.02; Form U-1 No. 70-7121, Ex 4; Form U-1 No. 70-7233, Ex 3; Form U-1 No. 70-7676, Ex 3; Form U-1 No. 70-7934, Ex 10; Form U-1 No. 72-8041, Ex 10(b); Form U-1 No. 70-8041, Ex 10(c); Form U-1 No. 70-8239, Ex 10(a).
4(b)	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo: (1) Subordinated Indenture, dated as of September 1, 2003, between SWEPCo and the Bank of New York, as Trustee. (2) Amended and Restated Trust Agreement of SWEPCo Capital Trust I, dated as of September 1, 2003, among SWEPCo, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustees. (3) Guarantee Agreement, dated as of September 1, 2003, delivered by SWEPCo for the benefit of the holders of SWEPCo Capital Trust Is Preferred Securities. (4)First Supplemental Indenture dated as of October 1, 2003, providing for the issuance of Series B Junior Subordinated Debentures between SWEPCo, as Issuer and the Bank of New York, as Trustee (5)Agreement as to Expenses and Liabilities, dated as of October 1, 2003 between SWEPCo and SWEPCo Capital Trust I (included in Item (4) above as Ex 4(f)(i)(A).	2003 Form 10-K, Ex 4(b).
4(c)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-87834, Ex 4(a)(b); Registration Statement No. 333-600632, Ex 4(b); Registration Statement No. 333-108045, Ex 4(b).
4(d)	Third Supplemental Indenture, between SWEPCo and The Bank of New York, as Trustees, dated April 11, 2003, establishing terms of 5.375% Senior Notes, Series C, due 2015.	2003 Form 10-K, Ex 4(d).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).

10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of SWEPCo.	**AEP** 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: TCC File No. 0-346	
3(a)	Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation.	Form 10-Q, Ex 3.1, March 31, 1997.
3(b)	Articles of Amendment to Restated Articles of Incorporation of TCC dated December 18, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TCC (amended as of April 19, 2000).	2000 Form 10-K, Ex 3(b).
4(a)	Indenture (for unsecured debt securities), dated as of November 15, 1999, between TCC and The Bank of New York, as Trustee, as amended and supplemented.	2000 Form 10-K, Ex 4(c)(d)(e).
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(d).
4(c)	First Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(e).
4(d)	Second Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 6.65% Senior Notes, Series B, due 2033 and 6.65% Senior Notes, Series E, due 2033.	2003 Form 10-K, Ex 4(f).
4(e)	Third Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 3.00% Senior Notes, Series C, due 2005 and 3.00% Senior Notes, Series F, due 2005.	2003 Form 10-K, Ex 4(g).
4(f)	Fourth Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of Floating Rate Notes, Series A, due 2005 and Floating Rate Notes, Series B, due 2005.	2003 Form 10-K, Ex 4(h).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(c)	Purchase and Sale Agreement, dated as of September 3, 2004, by and between TCC and City of San Antonio (acting by and through the City Public Service Board of San Antonio) and Texas Genco, L.P.	Form 10-Q, Ex. 10(a), September 30, 2004.
*12	Statement re: Computation of Ratios.	

*13	Copy of those portions of the TCC 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.	
21	List of subsidiaries of TCC.	**AEP** 2004 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
	REGISTRANT: TNC File No. 0-340	
3(a)	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation.	1996 Form 10-K, Ex 3.5.
3(b)	Articles of Amendment to Restated Articles of Incorporation of TNC dated December 17, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TNC (amended as of May 1, 2000).	Form 10-Q, Ex 3.4, March 31, 2000.
4(a)	Indenture, dated August 1, 1943, between TNC and Harris Trust and Savings Bank and J. Bartolini, as Trustees, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.05; Registration Statement No. 2-63931, Ex 2.02; Registration Statement No. 2-74408, Ex 4.02; Form U-1 No. 70-6820, Ex 12; Form U-1 No. 70-6925, Ex 13; Registration Statement No. 2-98843, Ex 4(b); Form U-1 No. 70-7237, Ex 4; Form U-1 No. 70-7719, Ex 3; Form U-1 No. 70-7936, Ex 10; Form U-1 No. 70-8057, Ex 10; Form U-1 No. 70-8265, Ex 10; Form U-1 No. 70-8057, Ex 10(b); Form U-1 No. 70-8057, Ex 10(c).
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(b).
4(c)	First Supplemental Indenture, dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(c).
10(a)	Restated and Amended Operating Agreement, dated as of January 1, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(a).
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	

*13	Copy of those portions of the TNC 2004 Annual Report (for the fiscal year ended December 31, 2004) which are incorporated by reference in this filing.
*24	Power of Attorney.
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

Exhibit10(c)(1)

PJM Interconnection, L.L.C.

Third Revised Rate Schedule FERC No. 24

AMENDED AND RESTATED

OPERATING AGREEMENT

OF

PJM INTERCONNECTION, L.L.C.

The following sheets reflect all revisions approved by FERC in orders issued through January 25, 2005, and all revisions from compliance filings submitted through January 27, 2005. Various sheets contain revisions that will be made in a filing expected to be submitted by the end of January 2005 (the clean-up filing). The revisions provide appropriate, updated designations.

OPERATING AGREEMENT

TABLE OF CONTENTS

IssuedBy: Craig Glazer Effective: June 29, 2004
Vice President, Government Policy
IssuedOn: April 29, 2004

IssuedBy: Craig Glazer Effective: October 1,2003
Vice President, Governmental Policy
IssuedOn: July 31, 2003

IssuedOn: November 1, 2004

IssuedOn: November 6, 2003

IssuedBy:	Craig Glazer Vice President, Governmental Policy	Effective:	March 20, 2003
IssuedOn:	March 20, 2003		

IssuedBy:	Craig Glazer Vice President, Government Policy	Effective:	October 1, 2004
IssuedOn:	September 1, 2004		

IssuedOn: November 2, 2004
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. EL03-236-000, issued May 6, 2004, 107 FERC 61,112.

IssuedBy: Craig Glazer Effective: May 1, 2004
Vice President, Governmental Policy
IssuedOn: December 31, 2003

IssuedBy: Craig Glazer
Vice President, Governmental Policy
IssuedOn: November 6, 2003

Effective: November7,2003

AMENDED AND RESTATED

OPERATING AGREEMENT

of

PJM INTERCONNECTION, L.L.C.

This Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of this 2[nd] day of June, 1997, amends and restates as of the Effective Date the Operating Agreement of PJM Interconnection, L.L.C. filed with the FERC on April 2, 1997, as amended.

WHEREAS, certain of the Members have previously entered into an agreement, originally dated September 26, 1956, as amended and supplemented up to and including December 31, 1996, stating their respective rights and obligations with respect to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems (such agreement as amended and supplemented being referred to as the Original PJM Agreement), and which coordinated operations and interchange came to be known as the PJM Interconnection; and

WHEREAS, pursuant to a resolution of June 16, 1993, an unincorporated association comprised of the parties to the Original PJM Agreement was formed for the purpose of implementation of the Original PJM Agreement as it then existed and as it subsequently has been amended and supplemented, such association being known as the PJM Interconnection Association; and

WHEREAS, because of changes in federal law and policy, the Original PJM Agreement, together with other documents and agreements, was amended, restated and submitted to FERC on December 31, 1996 to restructure fundamental aspects of the operation of the Interconnection; and

WHEREAS, so that the provisions of the Original PJM Agreement could be placed into effect consistent with a February 28, 1997 order of FERC, including those provisions related to the governance of the Interconnection, the parties to the Original PJM Agreement, along with the other interested parties, approved the conversion of the PJM Interconnection Association into the LLC pursuant to the provisions of the Delaware Limited Liability Company Act, as amended (the Delaware LLC Act), pursuant to a Certificate of Formation (the Certificate of Formation) and a Certificate of Conversion (the Certificate of Conversion), each filed with the Delaware Secretary of State (the Recording Office) on March 31, 1997; and

WHEREAS, the Members wish to amend and restate the Operating Agreement of PJM Interconnection, L.L.C. adopted in connection with the formation of the LLC and as in effect immediately prior to the Effective Date in the form set forth below; and

WHEREAS, the Members intend to form an Independent System Operator in accordance with the regulations of the Federal Energy Regulatory Commission; and

WHEREAS, the Members wish to amend and restate the Operating Agreement to provide for expansion of the operations of PJM Interconnection, L.L.C. into additional Control Areas.

Now, therefore, in consideration of the foregoing, and of the covenants and agreements hereinafter set forth, the Members hereby agree as follows:

1. DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used in this Agreement shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Sections, Schedules, Exhibits or Appendices are to Sections, Schedules, Exhibits or Appendices of this Agreement. As used in this Agreement:

1.1 Act.

Act shall mean the Delaware Limited Liability Company Act, Title 6, 18-101 to 18-1109 of the Delaware Code.

1.2 Affiliate.

Affiliate shall mean any two or more entities, one of which controls the other or that are under common control. Control shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of this Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entitys board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

1.2A Affected Member.

Affected Member shall mean a Member which as a result of its participation in PJMs markets or its membership in the LLC PJM provided confidential information to the Office of the Interconnection, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

1.3 Agreement.

Agreement shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time.

1.4 Annual Meeting of the Members.

Annual Meeting of the Members shall mean the meeting specified in Section 8.3.1 of this Agreement.

IssuedBy:	Craig Glazer Vice President, Government Policy	Effective:	June 29, 2004
IssuedOn:	April 29, 2004		

1.4A Authorized Commission.

Authorized Commission shall mean (i) a State public utility commission within the geographic limits of the PJM Region that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

1.4B Authorized Person.

Authorized Person shall mean a person who has executed a Non-Disclosure Agreement, and is authorized in writing by an Authorized Commission to receive and discuss confidential information. Authorized Persons may include attorneys representing an Authorized Commission, consultants and/or contractors directly employed by an Authorized Commission, provided however that consultants or contractors may not initiate requests for confidential information from the Office of the Interconnection or the PJM Market Monitor.

1.5 Board Member.

Board Member shall mean a member of the PJM Board.

1.5A Applicable Regional Reliability Council.

Applicable Regional Reliability Council shall mean the reliability council for the region in which a Member operates.

1.5B Behind The Meter Generation: Behind The Meter Generation refers to one or more generating units that are located with load at a single electrical location such that no transmission or distribution facilities owned or operated by any Transmission Owner or Electric Distributor are used to deliver energy from the generating unit[s] to the load; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit[s] capacity that is designated as a Capacity Resource, or (ii) in any hour, any portion of the output of the generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

IssuedBy:	Craig Glazer Vice President, Government Policy	Effective:	June 29, 2004
IssuedOn:	April 29, 2004		

1.6 Capacity Resource.

Capacity Resource shall mean the net capacity from owned or contracted for generating facilities all of which (i) are accredited to a Load Serving Entity pursuant to the procedures set forth in the Reliability Assurance Agreement and (ii) are committed to satisfy that Load Serving Entitys obligations under the Reliability Assurance Agreement and this Agreement.

1.7 Control Area.

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and the applicable regional reliability council of NERC;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7.01 Control Zone.

Control Zone shall mean any of the ECAR Control Zone(s), MAAC Control Zone, or MAIN Control Zone(s).

1.7.02 Default Allocation Assessment.

Default Allocation Assessment shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7A East Transmission Owner.

East Transmission Owner shall mean a Transmission Owner that has executed the East Transmission Owners Agreement.

1.7B East Transmission Owners Agreement.

East Transmission Owners Agreement shall mean that certain agreement, dated June 2, 1997 and as amended from time to time, by and among Transmission Owners in the PJM Control Area providing for an open-access transmission tariff in the MAAC Control Zone, and for other purposes.

1.7C ECAR.

ECAR shall mean the reliability council under section 202 of the Federal Power Act, established pursuant to the ECAR Coordination Agreement dated June 1, 1968, or any successor thereto.

1.7D ECAR Control Zone

ECAR Control Zone shall mean any one of the one or more Control Zones comprised of the Transmission Facilities of one or more of the Transmission Owners for which ECAR is the Applicable Regional Reliability Council, as designated in the PJM Manuals.

1.8 Electric Distributor.

Electric Distributor shall mean a Member that owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region.

1.9 Effective Date.

Effective Date shall mean August 1, 1997, or such later date that FERC permits this Agreement to go into effect.

1.10 Emergency.

Emergency shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

1.11 End-Use Customer.

End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.12 FERC.

FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over this Agreement.

1.13 Finance Committee.

Finance Committee shall mean the body formed pursuant to Section 7.5.1 of this Agreement.

1.14 Generation Owner.

Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.15 Good Utility Practice.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods 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. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.16 Information Request.

Information Request shall mean a written request, in accordance with the terms of this Agreement for disclosure of confidential information pursuant to Section 18.17.4 of this Agreement.

1.17 LLC.

LLC shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

1.18 Load Serving Entity.

Load Serving Entity shall mean an entity, including a load aggregator or power marketer, (1) serving end-users within the PJM Region, and (2) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region, or the duly designated agent of such an entity.

1.19 Locational Marginal Price.

Locational Marginal Price shall mean the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.20 MAAC.

MAAC shall mean the Mid-Atlantic Area Council, a reliability council under 202 of the Federal Power Act established pursuant to the MAAC Agreement dated August 1, 1994 or any successor thereto.

1.20A MAAC Control Zone.

MAAC Control Zone shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

1.20B MAIN.

MAIN shall mean the Mid-America Interconnected Network, a reliability council under 202 of the Federal Power Act established pursuant to the Amended and Restated Bylaws of MAIN, dated January 8, 1998, or any successor thereof.

1.20C MAIN Control Zone.

MAIN Control Zone shall mean any one of the one or more Control Zones comprised of the Transmission Facilities of one or more of the Transmission Owners for which MAIN is the Applicable Regional Reliability Council, as designated in the PJM Manuals.

1.21 Market Buyer.

Market Buyer shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make purchases in the PJM Interchange Energy Market or PJM Capacity Credit.

1.22 Market Participant.

Market Participant shall mean a Market Buyer or a Market Seller, or both.

1.23 Market Seller.

Market Seller shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make sales in the PJM Interchange Energy Market or PJM Capacity Credit Market.

1.24 Member.

Member shall mean an entity that satisfies the requirements of Section 11.6 of this Agreement and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Schedule 4 hereof.

1.25 Members Committee.

Members Committee shall mean the committee specified in Section 8 of this Agreement composed of representatives of all the Members.

1.26 NERC.

NERC shall mean the North American Electric Reliability Council, or any successor thereto.

1.26A Non-Disclosure Agreement.

Non-Disclosure Agreement shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

1.27 Office of the Interconnection.

Office of the Interconnection shall mean the employees and agents of the LLC engaged in implementation of this Agreement and administration of the PJM Tariff, subject to the supervision and oversight of the PJM Board acting pursuant to this Agreement.

1.28 Operating Reserve.

Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of a Control Zone, as specified in the PJM Manuals.

1.29 Original PJM Agreement.

Original PJM Agreement shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

1.30 Other Supplier.

Other Supplier shall mean a Member that is (i) engaged in buying, selling or transmitting electric energy in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.31 PJM Board.

PJM Board shall mean the Board of Managers of the LLC, acting pursuant to this Agreement.

1.31A PJM Capacity Credit Market.

PJM Capacity Credit Market shall be as defined in Schedule 11 to this Agreement.

1.32 PJM Control Area.

PJM Control Area shall mean the Control Area recognized by NERC as the PJM Control Area.

1.33 PJM Dispute Resolution Procedures.

PJM Dispute Resolution Procedures shall mean the procedures for the resolution of disputes set forth in Schedule 5 of this Agreement.

1.34 PJM Interchange Energy Market.

PJM Interchange Energy Market shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Schedule 1 to this Agreement.

1.35 PJM Manuals.

PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

1.35.01 PJM Market Monitor.

PJM Market Monitor shall mean the Market Monitoring Unit established under Attachment M to the PJM Tariff.

1.35A PJM Region.

PJM Region shall mean the aggregate of the MAAC Control Zone and the PJM West Region.

1.36 PJM Tariff.

PJM Tariff shall mean the PJM Open Access Transmission Tariff providing transmission service within the PJM Region, including any schedules, appendices, or exhibits attached thereto, as in effect from time to time.

1.36A [Reserved.]

1.36B PJM West Region.

PJM West Region shall mean the aggregate of the ECAR Control Zone(s) and MAIN Control Zone(s).

1.37 Planning Period.

Planning Period shall initially mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period established under the procedures of, as applicable, the Reliability Assurance Agreement or the Reliability Assurance Agreement-West.

1.38 President.

President shall have the meaning specified in Section 9.2.

1.38A Regulation Zone.

Regulation Zone shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.39 Related Parties.

Related Parties shall mean, solely for purposes of the governance provisions of this Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of this Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public bodys regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

1.40 Reliability Assurance Agreement.

Reliability Assurance Agreement shall mean that certain agreement, dated June 2, 1997 and as amended from time to time, establishing obligations, standards and procedures for maintaining the reliable operation of the PJM Control Area.

1.40A Reliability Assurance Agreement-West.

Reliability Assurance Agreement-West shall mean that certain agreement, dated March 13, 2001 and as amended from time to time, establishing obligations, standards and procedures for maintaining the reliable operation of the PJM West Region.

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1.41 Sector Votes.

Sector Votes shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Section 8.4.

1.41A Senior Standing Committees.

Senior Standing Committees shall mean the Members Committee, Electricity Markets Committee, and Reliability Committee, as established in Sections 8.1 and 8.6.

1.41A.01 Spinning Reserve Zone.

Spinning Reserve Zone shall mean the MAAC Control Zone or any of those geographic areas consisting of a combination of one or more of the Control Zone(s) in the PJM West Region as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirement for, spinning reserve service.

1.41B Standing Committees.

Standing Committees shall mean the Members Committee, the committees established and maintained under Section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

1.42 State.

State shall mean the District of Columbia and any State or Commonwealth of the United States.

1.42.01 State Certification.

State Certification shall mean the Certification of an Authorized Commission, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

1.42A State Consumer Advocate.

State Consumer Advocate shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, *inter alia* , for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.43 System.

System shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

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1.43A Third Party Request.

Third Party Request shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or PJM Market Monitor. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

1.44 Transmission Facilities.

Transmission Facilities shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERCs Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the transmission system of the PJM Region and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.

1.45 Transmission Owner.

Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.46 [Reserved.]

1.47 User Group.

User Group shall mean a group formed pursuant to Section 8.7 of this Agreement.

1.48 Voting Member.

Voting Member shall mean (i) a Member as to which no other Member is an Affiliate or Related Party, or (ii) a Member together with any other Members as to which it is an Affiliate or Related Party.

1.49 Weighted Interest.

Weighted Interest shall be equal to (0.1(1/N) + 0.5(B/C) + 0.2(D/E) + 0.2(F/G)), where:

the total number of Members excluding *ex officio* Members and State Consumer Advocates (which, for purposes of Section 15.2 of this agreement, shall be calculated as of five oclock p.m. Eastern Time on the date PJM declares a Member in default)

the Members internal peak demand for the previous calendar year (which, for Load Serving Entities under the Reliability Assurance Agreement, shall be that used to calculate Accounted For Obligation as determined by the Office of the Interconnection pursuant to Schedule 7 of the Reliability Assurance Agreement averaged over the previous calendar year)

C = the sum of factor B for all Members

the Members generating capability from Capacity Resources located in the PJM Region as of January 1 of the current calendar year, determined by the Office of the Interconnection pursuant to Schedule 9 of the Reliability Assurance Agreement or Schedule 9 of the West Reliability Assurance Agreement, respectively

E = the sum of factor D for all Members

the sum of the Members circuit miles of transmission facilities multiplied by the respective operating voltage for facilities 100 kV and above as of January 1 of the current calendar year

G = the sum of factor F for all Members

1.50 West Transmission Owner.

West Transmission Owner shall mean a Transmission Owner that has executed the West Transmission Owners Agreement.

1.51 West Transmission Owners Agreement.

West Transmission Owners Agreement shall mean that certain West Transmission Owners Agreement, dated March 13, 2001, as it may be amended hereafter.

1.52 Zone

Zone shall mean an area within the PJM Region, as set forth in Attachment J to the PJM Tariff.

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2. FORMATION, NAME; PLACE OF BUSINESS

2.1 Formation of LLC; Certificate of Formation.

The Members of the LLC hereby:

(a) acknowledge the conversion of the PJM Interconnection Association into the LLC, a limited liability company pursuant to the Act, by virtue of the filing of both the Certificate of Formation and the Certificate of Conversion with the Recording Office, effective as of March 31, 1997;

(b) confirm and agree to their status as Members of the LLC;

(c) enter into this Agreement for the purpose of amending and restating the rights, duties, and relationship of the Members; and

(d) agree that if the laws of any jurisdiction in which the LLC transacts business so require, the PJM Board also shall file, with the appropriate office in that jurisdiction, any documents necessary for the LLC to qualify to transact business under such laws; and (ii) agree and obligate themselves to execute, acknowledge, and cause to be filed for record, in the place or places and manner prescribed by law, any amendments to the Certificate of Formation as may be required, either by the Act, by the laws of any jurisdiction in which the LLC transacts business, or by this Agreement, to reflect changes in the information contained therein or otherwise to comply with the requirements of law for the continuation, preservation, and operation of the LLC as a limited liability company under the Act.

2.2 Name of LLC.

The name under which the LLC shall conduct its business is PJM Interconnection, L.L.C.

2.3 Place of Business.

The location of the principal place of business of the LLC shall be 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497. The LLC may also have offices at such other places both within and without the State of Delaware as the PJM Board may from time to time determine or the business of the LLC may require.

2.4 Registered Office and Registered Agent.

The street address of the initial registered office of the LLC shall be 1209 Orange Street, Wilmington, Delaware 19801, and the LLCs registered agent at such address shall be The Corporation Trust Company. The registered office and registered agent may be changed by resolution of the PJM Board.

3. PURPOSES AND POWERS OF LLC

3.1 Purposes.

The purposes of the LLC shall be:

(a) to operate in accordance with FERC requirements as an Independent System Operator, comprised of the PJM Board, the Office of the Interconnection, and the Members Committee, with the authorities and responsibilities set forth in this Agreement;

(b) as necessary for the operation of the PJM Region as specified above: (i) to acquire and obtain licenses, permits and approvals, (ii) to own or lease property, equipment and facilities, and (iii) to contract with third parties to obtain goods and services, provided that, the LLC may procure goods and services from a Member only after open and competitive bidding; and

(c) to engage in any lawful business permitted by the Act or the laws of any jurisdiction in which the LLC may do business and to enter into any lawful transaction and engage in any lawful activities in furtherance of the foregoing purposes and as may be necessary, incidental or convenient to carry out the business of the LLC as contemplated by this Agreement.

3.2 Powers.

The LLC shall have the power to do any and all acts and things necessary, appropriate, advisable, or convenient for the furtherance and accomplishment of the purposes of the LLC, including, without limitation, to engage in any kind of activity and to enter into and perform obligations of any kind necessary to or in connection with, or incidental to, the accomplishment of the purposes of the LLC, so long as said activities and obligations may be lawfully engaged in or performed by a limited liability company under the Act.

4. EFFECTIVE DATE AND TERMINATION

4. Effective Date and Termination.
1

(a) The existence of the LLC commenced on March 31, 1997, as provided in the Certificate of Formation and Certificate of Conversion which were filed with the Recording Office on March 31, 1997. This Agreement shall amend and restate the Operating Agreement of PJM Interconnection, LLC as of the Effective Date.

(b) The LLC shall continue in existence until terminated in accordance with the terms of this Agreement. The withdrawal or termination of any Member is subject to the provisions of Section 18.18 of this Agreement.

(c) Any termination of this Agreement or withdrawal of any Member from the Agreement shall be filed with the FERC pursuant to Section 205 of the Federal Power Act and shall become effective only upon the FERCs approval, acceptance without suspension, or, if suspended, the expiration of the suspension period before the FERC has issued an order on the merits of the filing.

4.2 Governing Law.

This Agreement and all questions with respect to the rights and obligations of the Members, the construction, enforcement and interpretation hereof, and the formation, administration and

termination of the LLC shall be governed by the provisions of the Act and other applicable laws of the State of Delaware, and the Federal Power Act.

5. WORKING CAPITAL AND CAPITAL CONTRIBUTIONS

5.1 Funding of Working Capital and Capital Contributions.

(a) The Office of the Interconnection shall attempt to obtain financing of up to twenty-five percent (25%) of the approved annual operating budget of the LLC adopted by the PJM Board pursuant to Section 7.5.2 of this Agreement to meet the working capital needs of the LLC, which shall be limited to such working capital needs that arise from timing in cash flows from interchange accounting, tariff administration and payment of the operating costs of the Office of the Interconnection. Such financing, which shall be non-recourse to the Members of the LLC and which shall be for a stated term without penalty for prepayment, may be obtained by borrowing the amount required at market-based interest rates, negotiated on an arms length basis, (i) from a Member or Members or (ii) from a commercial lender, supported, if necessary, by credit enhancements provided by a Member or Members; *provided, however* , no Member shall be obligated to provide such financing or credit enhancements. The LLC shall make such filings and seek such approvals as necessary in order for the principal, interest and fees related to any such borrowing to be repaid through charges under the PJM Tariff as appropriate under Schedule 3 of this Agreement.

(b) In the event financing of the working capital needs of the Office of the Interconnection is unavailable on commercially reasonable terms, the PJM Board may require the Members to contribute capital in the aggregate up to five million two hundred thousand dollars ($5,200,000) for the working capital needs that could not be financed; provided that in such event each Members obligation to contribute additional capital shall be in proportion to its Weighted Interest, multiplied by the amount so requested by the PJM Board. Each Member that contributes such capital shall be entitled to earn a return on the contribution to the extent such contribution has not been repaid, which return shall be at a fair market rate as determined by the PJM Board but in no event less than the current interest rate established pursuant to 18 C.F.R. 35.19a(a)(2)(iii); *provided further* , that any Member not wanting to contribute the requested capital contribution may withdraw from the LLC upon 90 days written notice as provided in Section 18.18.2 of this Agreement.

(c) Authority to borrow capital for LLC Operations. Nothing in Section 5.1(a) and (b) shall be construed to restrict the authority of the PJM Board to authorize the LLC to borrow or raise capital in excess of twenty-five percent of the approved annual operating budget of the LLC, for working capital or otherwise, as the PJM Board deems appropriate to fund the operations of the LLC, in accordance with the general powers of the LLC under Section 3.2 to enter into obligations of any kind to accomplish the purposes of the LLC. Nor shall anything in Section 5.1(a) and (b) in any way restrict the authority of the PJM Board to authorize the LLC to grant to lenders such security interests or other rights in assets or revenues received under the PJM Tariff with respect to the costs of operating the LLC and the Office of the Interconnection and to take such other actions as it deems necessary and appropriate to obtain such financing in accordance with such general powers of the LLC under Section 3.2.

5.2 Contributions to Association.

All contributions prior to the Effective Date of the original Operating Agreement of PJM Interconnection, L.L.C. of cash or other assets to the PJM Interconnection Association by persons who are now or in the future may become Members of the LLC shall be deemed contributions by such Members to the LLC.

6. TAX STATUS AND DISTRIBUTIONS

6.1 Tax Status.

The LLC shall make all necessary filings under the applicable Treasury Regulations to have the LLC taxed as a corporation.

6. Return of Capital Contributions.
2

(a) In the event Members are required to contribute capital to the LLC in accordance with Section 5.1 herein, the LLC shall request the Transmission Owners to recover such working capital through charges under the PJM Tariff as provided in Schedule 3 of this Agreement. In the event all or a portion of the working capital is recovered pursuant to the PJM Tariff, such amount(s) shall be returned to the Members in accordance with their actual contributions.

(b) Except for return of capital contributions and liquidating distributions as provided in the foregoing section and Section 6.3 herein, respectively, the LLC does not intend to make any distributions of cash or other assets to its Members.

6. Liquidating Distribution.
3

Upon termination or liquidation of the LLC, the cash or other assets of the LLC shall be distributed as follows:

(a) first, in the event the LLC has any liabilities at the time of its termination or dissolution, the LLC shall liquidate such of its assets as is necessary to satisfy such liabilities;

(b) second, any capital contribution in cash or in kind by any Member of the PJM Interconnection Association prior to the Effective Date shall be distributed by the LLC back to such Member in the form received by the PJM Interconnection Association; and

(c) third, any remaining assets of the LLC shall be distributed to the Members in proportion to their Weighted Interests.

7. PJM BOARD

7.1 Composition.

There shall be an LLC Board of Managers, referred to herein as the PJM Board, composed of nine voting members, with the President as a non-voting member. The nine voting Board Members shall be elected by the Members Committee. A Nominating Committee, consisting of one representative elected annually from each sector of the Members Committee

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established under Section 8.1 and three voting Board Members (provided that one such Board Member shall serve only as a non-voting member of the Nominating Committee), shall retain an independent consultant, which shall be directed to prepare a list of persons qualified and willing to serve on the PJM Board. Not later than 30 days prior to each Annual Meeting of the Members, the Nominating Committee shall distribute to the representatives on the Members Committee one nominee from among the list proposed by the independent consultant for each vacancy or expiring term on the PJM Board, along with information on the background and experience of the nominees appropriate to evaluating their fitness for service on the PJM Board; provided, however, that the Nominating Committee in its discretion may nominate, without retaining an independent consultant, a Board member whose term is expiring and who desires to serve an additional term. Elections for the PJM Board shall be held at each Annual Meeting of the Members, for the purpose of selecting the initial PJM Board in accordance with the provisions of Section 7.3(a), or selecting a person to fill the seat of a Board Member whose term is expiring. Should the Members Committee fail to elect a full PJM Board from the nominees proposed by the Nominating Committee, then the Nominating Committee shall propose a further nominee from the list prepared by the independent consultant (or a replacement consultant) for each remaining vacancy on the PJM Board for consideration by the Members at the next regular meeting of the Members Committee.

7.2 Qualifications.

A Board Member shall not be, and shall not have been at any time within five years of election to the PJM Board, a director, officer or employee of a Member or of an Affiliate or Related Party of a Member. Except as provided in the LLCs Standards of Conduct filed with the FERC, at any time while serving on the PJM Board, a Board Member shall have no direct business relationship or other affiliation with any Member or its Affiliates or Related Parties. Of the nine Board Members, four shall have expertise and experience in the areas of corporate leadership at the senior management or board of directors level, or in the professional disciplines of finance or accounting, engineering, or utility laws and regulation, one shall have expertise and experience in the operation or concerns of transmission dependent utilities, one shall have expertise and experience in the operation or planning of transmission systems, and one shall have expertise and experience in the area of commercial markets and trading and associated risk management.

7.3 Term of Office.

(a) The persons serving as the Board of Managers of the LLC immediately prior to the Effective Date shall continue in office until the first Annual Meeting of the Members. At the first Annual Meeting of the Members, the then current members of the PJM Board who desire to continue in office shall be elected by the Members to serve until the second Annual Meeting of the Members or until their successors are elected, along with such additional persons as necessary to meet the composition requirements of Section 7.1 and the qualification requirements of Section 7.2.

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(b) A Board Member shall serve for a term of three years commencing with the Annual Meeting of the Members at which the Board Member was elected; provided, however, that two of the Board Members elected at the first Annual Meeting of the Members following the Effective Date shall be chosen by lot to serve a term of one year, three of such Board Members shall be chosen by lot to serve a term of two years and the final two such Board Members shall serve a term of three years; provided further, however, that the initial term of one of the two Board Members elected to fill one of the two new Board seats added in 2003 shall be chosen by lot to serve a term of four years and the initial term of the other Board Member elected to fill the other new Board seat added in 2003 shall serve a term of five years.

(c) Vacancies on the PJM Board occurring between Annual Meetings of the Members shall be filled by vote of the then remaining Board Members; a Board Member so selected shall serve until the next Annual Meeting at which time a person shall be elected to serve the balance of the term of the vacant Board Seat. Removal of a Board Member shall require the approval of the Members Committee.

7.4 Quorum.

The presence in person or by telephone or other authorized electronic means of a majority of the voting Board Members shall constitute a quorum at all meetings of the PJM Board for the transaction of business except as otherwise provided by statute. If a quorum shall not be present, the Board Members then present shall have the power to adjourn the meeting from time to time, until a quorum shall be present. Provided a quorum is present at a meeting, the PJM Board shall act by majority vote of the Board Members present.

7. Operating and Capital Budgets.
5

7.5.1 Finance Committee.

Not later than June 1 of each year, the entities specified below shall select the members of a Finance Committee. The Finance Committee shall be composed of one representative elected annually from each sector of the Members Committee as defined in section 8.1, one representative of the Office of the Interconnection selected by the President, and two Board Members selected by the PJM Board. The Office of the Interconnection shall prepare annual operating and capital budgets in accordance with processes and procedures established by the PJM Board, and shall timely submit its budgets to the Finance Committee for review. The Finance Committee shall submit its analysis of and recommendations on the budgets to the PJM Board, with copies to the Members Committee. The Finance Committee shall also review and comment upon any additional or amended budgets prepared by the Office of the Interconnection at the request of the PJM Board or the Members Committee.

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7.5.2 Adoption of Budgets.

The PJM Board shall adopt, upon consideration of the advice and recommendations of the Finance Committee, operating and capital budgets for the LLC, and shall distribute to the Members for their information final annual budgets for the following fiscal year not later than 60 days prior to the beginning of each fiscal year of the LLC.

7.6 By-laws.

To the extent not inconsistent with any provision of this Agreement, the PJM Board shall adopt such by-laws establishing procedures for the implementation of this Agreement as it may deem appropriate, including but not limited to by-laws governing the scheduling, noticing and conduct of meetings of the PJM Board, selection of a Chair and Vice Chair of the PJM Board, action by the PJM Board without a meeting, and the organization and responsibilities of standing and special committees of the PJM Board. Such by-laws shall not modify or be inconsistent with any of the rights or obligations established by this Agreement.

7.7 Duties and Responsibilities of the PJM Board.

In accordance with this Agreement, the PJM Board shall supervise and oversee all matters pertaining to the PJM Region and the LLC, and carry out such other duties as are herein specified, including but not limited to the following duties and responsibilities:

i) As its primary responsibility, ensure that the President, the other officers of the LLC, and Office of the Interconnection perform the duties and responsibilities set forth in this Agreement, including but not limited to those set forth in Sections 9.2 through 9.4 and Section 10.4 in a manner consistent with (A) the safe and reliable operation of the PJM Region, (B) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region, and (C) the principle that a Member or group of Members shall not have undue influence over the operation of the PJM Region;

ii) Select the Officers of the LLC;

iii) Adopt budgets for the LLC;

iv) Approve the Regional Transmission Expansion Plan in accordance with the provisions of the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of this Agreement;

v) On its own initiative or at the request of a User Group as specified herein, submit to the Members Committee such proposed amendments to this Agreement or any Schedule hereto, or a proposed new Schedule, as it may deem appropriate;

Petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the PJM Board believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal

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Power Act, subject to the right of any Member or the Members to intervene in any resulting proceedings;

vii) Review for consistency with the creation and operation of a robust, competitive and non-discriminatory electric power market in the PJM Region any change to rate design or to non-rate terms and conditions proposed by Transmission Owners for filing under section 205 of the Federal Power Act;

viii) If and to the extent it shall deem appropriate, intervene in any proceeding at FERC initiated by the Members in accordance with Section 11.5(b), and participate in other state and federal regulatory proceedings relating to the interests of the LLC;

ix) Review, in accordance with Section 15.1.3, determinations of the Office of the Interconnection with respect to events of default;

x) Assess against the other Members in proportion to their Default Allocation Assessment an amount equal to any payment to the Office of the Interconnection, including interest thereon, as to which a Member is in default;

xi) Establish reasonable sanctions for failure of a Member to comply with its obligations under this Agreement;

xii) Direct the Office of the Interconnection on behalf of the LLC to take appropriate legal or regulatory action against a Member (A) to recover any unpaid amounts due from the Member to the Office of the Interconnection under this Agreement and to make whole any Members subject to an assessment as a result of such unpaid amount, or (B) as may otherwise be necessary to enforce the obligations of this Agreement;

xiii) [Reserved.]

xiv) [Reserved.]

Solicit the views of Members on, and commission from time to time as it shall deem appropriate independent reviews of, (a) the performance of the PJM Interchange Energy Market, (b) compliance by Market Participants with the rules and requirements of the PJM Interchange Energy Market, and

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(c) the performance of the Office of the Interconnection under performance criteria proposed by the Members Committee and approved by the PJM Board; and

xvi) Terminate a Member as may be appropriate under the terms of this Agreement.

8. MEMBERS COMMITTEE

8.1 Sectors.

8.1.1 Designation .

Voting on the Senior Standing Committees shall be by sectors. The Senior Standing Committee shall be composed of five sectors, one for Generation Owners, one for Other Suppliers, one for Transmission Owners, one for Electric Distributors, and one for End-Use Customers, provided that there are at least five Members in each Sector. Except as specified in Section 8.1.2, each Voting Member shall have one vote. Each Voting Member shall, within thirty (30) days after the Effective Date or, if later, thirty (30) days after becoming a Member, and thereafter not later than 10 days prior to the Annual Meeting of the Members for each annual period beginning with the Annual Meeting of the Members, submit to the President a sealed notice of the sector in which it is qualified to vote or, if qualified to participate in more than one sector, its rank order preference of the sectors in which it wishes to vote, and shall be assigned to its highest-ranked sector that has the minimum number of Members specified above. If a Member is assigned to a sector other than its highest-ranked sector in accordance with the preceding sentence, its higher sector preference or preferences shall be honored as soon as a higher-ranked sector has five or more Members. A Voting Member may designate as its voting sector any sector for which it or its Affiliate or Related Party Members is qualified. The sector designations of the Voting Members shall be announced by the Office of the Interconnection at the Annual Meeting and shall apply to all Senior Standing Committees.

8.1.2 Related Parties .

The Members in a group of Related Parties shall each be entitled to a vote, provided that all the Members in a group of Related Parties that chooses to exercise such rights shall be assigned to the Electric Distributor sector.

8.2 Representatives.

8.2.1 Appointment.

Each Member may appoint one representative to serve on each of the Standing Committees, potentially a different person for each committee, with authority to act for that Member with respect to actions or decisions thereof. Each Member may appoint up to three alternate representatives to each such committee to act for that Member at meetings thereof in the absence of the representative. A Member participating in the PJM Interchange Energy Market through an agent may be represented on the Standing Committee by that agent. A Member shall appoint its representatives and alternates by giving written notice thereof to the Office of the Interconnection. Members that are Affiliates or Related Parties may each appoint a representative and alternate representatives to each of the Standing Committees, but shall vote on Senior Standing Committees as specified in Section 8.1.

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8.2.2 Regulatory Authorities.

FERC and any other federal agency with regulatory authority over a Member and each State electric utility regulatory commission with regulatory jurisdiction within the PJM Region, may nominate one representative to serve as an *ex officio* non-voting member on each of the Standing Committees.

8.2.3 State Offices of Consumer Advocate.

(a) Each State Consumer Advocate may nominate one representative to serve as an *ex officio* member on each of the Standing Committees. Upon a written request by a State Consumer Advocate to the Office of the Interconnection, and upon the payment of the fee prescribed by section (b) of Schedule 3 to this Agreement, a State Consumer Advocate may designate a representative to each of the Standing Committees who, subject to subparagraph b, shall be entitled to cast one (1) non-divisible vote in the End-Use Customer Sector in Senior Standing Committees. As an *ex officio* member, a State Consumer Advocate shall have no liability under this Agreement, other than the annual fee required by Schedule 3. The State Consumer Advocates shall not be entitled to indemnification by the other Members under any provisions of this Agreement. Additionally, the State Consumer Advocates shall not be eligible to participate in any markets managed by PJM under the terms contained in this Agreement.

(b) Each State Consumer Advocate shall be entitled to cast only one (1) vote in the Senior Standing Committees per State or the District of Columbia. If more than one representative from a given state has been nominated to be a voting member of the Senior Standing Committees, all State Offices of Consumer Advocate from such state that have nominated representatives to vote at the Senior Standing Committees shall designate to the Office of the Interconnection one (1) representative who shall be entitled to vote on all of their behalfs, prior to being permitted to vote at any meetings of the Senior Standing Committees.

8.2.4 Initial Representatives.

Initial representatives to the Members Committee shall be appointed no later than 30 days after the Effective Date; provided, however, that each representative to the Management Committee under the Operating Agreement of PJM Interconnection, L.L.C. as in effect immediately prior to the Effective Date shall automatically become a representative to the Members Committee on the Effective Date unless replaced as specified in Section 8.2.5. An entity becoming a Member shall appoint a representative to each Standing Committee no later than 30 days after becoming a Member.

8.2.5 Change of or Substitution for a Representative.

Any Member may change its representative or alternate on the Standing Committees at any time by providing written notice to the Office of the Interconnection identifying its replacement representative or alternate. Any representative to the Standing Committees may, by written notice to the applicable Chair, designate a substitute representative from that Member to act for him or her with respect to any matter specified in such notice.

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8.3 Meetings.

8.3.1 Regular and Special Meetings.

The Standing Committees shall hold regular meetings, no less frequently than once each calendar quarter at such time and at such place as shall be fixed by the Chair thereof. The Members Committee may adopt bylaws, including rules of procedure, governing its meetings and activities and the meetings and activities of the other Standing Committees, and other committees, subcommittees, task forces, working groups and other bodies under its auspices. The Members Committee shall hold an Annual Meeting of the Members each calendar year at such time and place as shall be specified by the Chair. At the Annual Meeting of the Members, Board Members as necessary shall be elected. The Standing Committees may hold special meetings for one or more designated purposes within the scope of the authority of the applicable committee when called by the Chair on the Chairs own initiative, or at the request of five or more representatives on the applicable committee. The notice of a regular or special meeting shall be distributed to the representatives as specified in Section 18.14 of this Agreement not later than seven days prior to the meeting, shall state the time and place of the meeting, and shall include an agenda sufficient to notify the representatives of the substance of matters to be considered at the meeting; provided, however, that meetings may be called on shorter notice at the discretion of the Chair as the Chair shall deem necessary to deal with an emergency or to meet a deadline for action.

8.3.2 Attendance.

Regular and special meetings may be conducted in person or by telephone, or other electronic means as authorized by the Members Committee. The attendance in person or by telephone or other electronic means of a representative or a duly designated substitute shall be required in order to vote.

8.3.3 Quorum.

The attendance as specified in Section 8.3.2 of a majority of the Voting Members from each of at least three sectors that each have at least five Members shall constitute a quorum at any meeting of the Members Committee; however, a quorum shall only require one-third of the Voting Members, but not less than ten, from any sector that has more than 20 Voting Members. No action may be taken by the Members Committee at a meeting unless a quorum is present; provided, however, that if a quorum is not present, the Voting Members then present shall have the power to adjourn the meeting from time to time until a quorum shall be present. A quorum shall not be required to conduct a meeting of any Committee other than the Members Committee; however, the Chair of any committee other than the Members Committee, in his discretion, may declare adjourned any meeting which fewer than ten Members attend.

8.4 Manner of Acting.

(a) The procedures for the conduct of meetings of the Standing Committees may be stated in bylaws adopted by the Members Committee.

(b) In a Senior Standing Committee, each Sector shall be entitled to cast one and zero one-hundredths (1.00) Sector Votes. Each Voting Member shall be entitled to cast one (1) non-divisible vote in its sector. In the case of a Voting Member comprised of Affiliates or Related Parties, any representative, alternate or substitute of any of the Affiliated or Related Parties may cast the vote of the Voting Member. The Sector Vote of each sector shall be split into an affirmative component based on votes for the pending motion, and a negative component based on votes against the pending motion, in direct proportion to the votes cast within the sector for and against the pending motion, rounded to two decimal places.

(c) The sum of affirmative Sector Votes necessary to pass a pending motion in a Senior Standing Committee shall be greater than (but not merely equal to) the product of .667 multiplied by the number of sectors that have at least five Members and that participated in the vote; provided, however, that the sum of the affirmative Sector Votes necessary to pass a motion to elect a Board Member or to elect the Chair or Vice Chair of the Members Committee shall be greater than (but not merely equal to) the product of .5 multiplied by the number of sectors that have at least five Members and that participated in the vote.

(d) Voting Members not in attendance at the meeting as specified in Section 8.3.2 of this Agreement or abstaining shall not be counted as affirmative or negative votes.

8.5 Chair and Vice Chair of the Members Committee.

8.5.1 Selection and Term.

The representatives or their alternates or substitutes on the Members Committee shall elect from among the representatives a Chair and a Vice Chair. The offices of Chair and Vice Chair shall be held for a term of one year. The terms shall commence at the last regular meeting of the Members Committee each calendar year and end at the last regular meeting of the Members Committee of the following calendar year or until succession to the office occurs as specified herein. Except as specified below, at the last regular meeting of the Members Committee each calendar year, the Vice Chair shall succeed to the office of Chair, and a new Vice Chair shall be elected. If the office of Chair becomes vacant, or the Chair leaves the employment of the Member for whom the Chair is the representative, or the Chair is no longer the representative of such Member, the Vice Chair shall succeed to the office of Chair, and a new Vice Chair shall be elected at the next regular or special meeting of the Members Committee, both such officers to serve until the last regular meeting of the Members Committee of the calendar year following such succession or election to a vacant office. If the office of Vice Chair becomes vacant, or the Vice Chair leaves the employment of the Member for whom the Vice Chair is the representative, or the Vice Chair is no longer the representative of such Member, a new Vice Chair shall be elected at the next regular or special meeting of the Members Committee.

Notwithstanding the foregoing, the Chair and Vice Chair whose terms commenced on May 1, 2003, shall hold their offices until the last regular meeting of the Members Committee in 2004, and there shall not be an election of a new Vice Chair at the last regular meeting of the Members Committee in 2003.

8.5.2 Duties.

The Chair shall call and preside at meetings of the Members Committee, and shall carry out such other responsibilities as the Members Committee shall assign. The Chair shall cause minutes of each meeting of the Members Committee to be taken and maintained, and shall cause notices of meetings of the Members Committee to be distributed. The Vice Chair shall preside at meetings of the Members Committee in the absence of the Chair, and shall otherwise act for the Chair at the Chairs request.

8.6 Senior, Standing, and Other Committees.

The Members Committee shall establish and maintain the Electricity Markets Committee and Reliability Committee as Senior Standing Committees. The Members Committee also shall establish and maintain the Market Implementation Committee (under the Electricity Markets Committee), and Planning Committee and Operating Committee (both under the Reliability Committee) as Standing Committees. The Members Committee may establish or dissolve other Standing Committees from time to time. The President shall appoint the Chair and Vice Chair of each Senior Standing Committee and Standing Committee and, after consultation with the Chair of a Standing Committee, the President shall appoint the Chair and Vice Chair of any other committees.

8.6.1 Electricity Markets Committee. The Electricity Markets Committee shall provide advice and recommendations concerning the operation of the PJM Interchange Energy Market and Ancillary Services markets and otherwise as directed by the Members Committee. Voting on the Electricity Markets Committee shall be by sectors in accordance with Sections 8.1 and 8.4 of this Agreement. The responsibilities of the Electricity Markets Committee shall, more specifically, include, but not be limited to, the following:

(a) The Electricity Markets Committee shall develop and approve an annual plan including prioritization of planned activities and initiation of activities supporting the approved plan.

(b) The Electricity Markets Committee shall provide advice and recommendations concerning issues pertaining to the operation and administration of the PJM markets, including but not limited to amendments to this Agreement, the PJM Tariff, or market rules and procedures as necessary or appropriate to foster competition and assure the fair, reliable and efficient operation and administration of the PJM markets.

(c) The Electricity Markets Committee shall provide advice and recommendations as are necessary or appropriate to assure a high level of economy of service in the operation of the PJM Interchange Energy Market and other markets, in accordance with established market operation principles, practices and procedures, recognizing individual participant requirements for services, contractual obligations and other pertinent factors.

(d) The Electricity Markets Committee shall provide advice and recommendations concerning studies and analyses relating to the overall efficacy of the PJM Interchange Energy Market and in carrying out actions as may be initiated as a result thereof.

(e) The Electricity Markets Committee shall provide direction to the Market Implementation Committee, which committee shall report to the Electricity Markets Committee. The Market Implementation Committee shall provide advice and recommendations to the Electricity Markets Committee directed to the advancement and promotion of competitive wholesale electricity markets in the PJM Region, and perform such other functions as the Electricity Markets Committee may direct from time to time.

(f) The Electricity Markets Committee shall perform such other functions, directly or through delegation to a Standing Committee, subcommittee, working group or task force reporting thereto, as the Members Committee may direct.

(g) The Electricity Markets Committee shall create subcommittees, working groups or task forces as and when necessary to assist in performing the duties of the Electricity Markets Committee.

8.6.2 Reliability Committee.

The Reliability Committee addresses matters related to the reliable and secure operation of the PJM system and planning strategies to assure the continued ability of the Members to operate reliably and economically, consistent with applicable reliability principles and standards. The Reliability Committee coordinates with the Electricity Markets Committee on mechanisms to provide an efficient marketplace for products needed for resource adequacy and operating security. Voting on the Reliability Committee shall be by sectors in accordance with Sections 8.1 and 8.4 of this Agreement. Neither the Reliability Committee nor the Members Committee shall have authority to control or direct the actions of the PJM Board or the Office of the Interconnection with regard to the short-term reliability of grid operations within the PJM Region. The responsibilities of the Reliability Committee shall, more specifically, include, but not be limited to, the following:

(a) The Reliability Committee shall develop and approve an annual plan including prioritization of planned activities and initiation of activities supporting the approved plan.

(b) The Reliability Committee shall provide advice and recommendations concerning revisions to this Agreement, the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the PJM Tariff that pertain to its areas of responsibility.

(c) The Reliability Committee shall make annual and timely recommendations concerning the generating capacity reserve requirement and related demand-side valuation factors for consideration by the Members Committee, in order to assist the Members Committee in making recommendations to the PJM Board.

(d) The Reliability Committee shall provide direction to the Operating Committee and Planning Committee, which committees shall report to the Reliability Committee. The Operating Committee shall advise the Reliability Committee and the Office of the Interconnection on matters pertaining to the reliable and secure operation of the PJM Region and other matters as the Reliability Committee may request. The Planning Committee shall advise the Reliability Committee and the Office of the Interconnection on matters pertaining to system reliability, security, economy of service, and planning strategies and policies and other matters as the Reliability Committee may request.

(e) The Reliability Committee shall perform such other functions, directly or through delegation to a Standing Committee, subcommittee, working group or task force reporting thereto, as the Members Committee may direct.

(f) The Reliability Committee shall create subcommittees, working groups or task forces as and when appropriate to assist in performing the duties of the Reliability Committee.

8.6.3 Other Committees and Bodies. The Standing Committees may form, select the membership, and oversee the activities, of such other committees, subcommittees, task forces, working groups or other bodies as it shall deem appropriate, to provide advice and recommendations to the Standing Committees or Office of the Interconnection. Each such group shall terminate automatically upon completion of its assigned tasks and, if not terminated, shall terminate two years after formation unless reauthorized by the Standing Committee that directed its formation.

8.6.4 Alternate Dispute Resolution Committee. The Members Committee shall elect representatives to the Alternate Dispute Resolution Committee as specified in the PJM Dispute Resolution Procedures.

8.7 User Groups.

(a) Any five or more Members sharing a common interest may form a User Group, and may invite such other Members to join the User Group as the User Group shall deem appropriate. Notification of the formation of a User Group shall be provided to all members of the Members Committee.

(b) The Members Committee shall create a User Group composed of representatives of *bona fide* public interest and environmental organizations that are interested in the activities of the LLC and are willing and able to participate in such a User Group.

(c) Meetings of User Groups shall be open to all Members and the Office of the Interconnection. Notices and agendas of meetings of a User Group shall be provided to all Members that ask to receive them.

(d) Any recommendation or proposal for action adopted by affirmative vote of three-fourths or more of the members of a User Group shall be submitted to the Chair of the Members Committee. The Chairman shall refer the matter for consideration by the applicable Standing Committee as appropriate for consideration at that Committees next regular meeting, occurring not earlier than 30 days after the referral, for a recommendation to the Members Committee for consideration at its next regular meeting.

(e) If the Members Committee does not adopt a recommendation or proposal submitted by a User Group, upon vote of nine-tenths or more of the members of the User Group the recommendation or proposal may be submitted to the PJM Board for its consideration in accordance with Section 7.7(v).

8.8 Powers of the Members Committee.

The Members Committee, acting by adoption of a motion as specified in Section 8.4, shall have the power to take the actions specified in this Agreement, including:

i Elect the members of the PJM Board;
)

i In accordance with the provisions of Section 18.6 of this Agreement, amend any portion of this Agreement, including the
i Schedules hereto, or create new Schedules, and file any such amendments or new Schedules with FERC or other regulatory body
) of competent jurisdiction;

i Adopt bylaws that are consistent with this Agreement, as amended or restated from time to time;
i
i
)

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(iv) Terminate this Agreement; and

(v) Provide advice and recommendations to the PJM Board and the Office of the Interconnection.

9. OFFICERS

9.1 Election and Term.

The officers of the LLC shall consist of a President, a Secretary and a Treasurer. The PJM Board may elect such other officers as it deems necessary to carry out the business of the LLC. All officers shall be elected by the PJM Board and shall hold office until the next annual meeting of the

PJM Board and until their successors are elected. Any number of offices may be held by the same person, except that the offices of the President and Treasurer may not be held by the same person.

9.2 President.

The PJM Board shall appoint a President and Chief Executive Officer of the LLC (the President). The President shall direct and supervise the day-to-day operation of the LLC, and shall report to the PJM Board. The President shall be responsible for directing and supervising the Office of the Interconnection in the performance of the duties and responsibilities specified in Section 10.4. The President shall execute bonds, mortgages and other contracts requiring a seal, under the seal of the LLC, except where required or permitted by law to be otherwise signed and executed and except where the signing and execution thereof shall be expressly delegated by the board to some other officer or agent of the LLC. In the absence of the President or in the event of his or her inability or refusal to act, and if a vice president has been appointed by the PJM Board, the Vice President (or in the event there be more than one Vice President, the Vice Presidents in the order designated by the PJM Board in its Minutes) shall perform the duties of the President, and when so acting, shall have all the powers of and be subject to all the restrictions upon the President. The Vice President shall perform such other duties and have such other powers as the PJM Board may from time to time prescribe.

9.3 Secretary.

The Secretary shall attend all meetings of the PJM Board and record all the proceedings of the meetings of the PJM Board in a minute book to be kept for that purpose and shall perform like duties for the standing committees or special committees when required. He or she shall give, or cause to be given, notice of all special meetings of the PJM Board, and shall perform such other duties as may be prescribed by the PJM Board or President, under whose supervision he or she shall be. He or she shall have custody of the corporate seal of the LLC, and he or she, or an assistant secretary, shall have authority to affix the same to any instrument requiring it and, when so affixed, it may be attested by his or her signature or by the signature of such assistant secretary. The PJM Board may give general authority to any other officer to affix the seal of the LLC and to attest the affixing by his or her signature.

9.4 Treasurer.

The Treasurer shall have or arrange for the custody of the LLCs funds and securities and shall keep full and accurate accounts of receipts and disbursements in books belongings to the LLC and shall deposit all moneys and other valuable effects in the name and to the credit of the LLC in such depositories as may be designated by the PJM Board. The Treasurer shall disburse the funds of the LLC as may be ordered by the PJM Board, taking proper vouchers for such disbursements, and shall render to the President and PJM Board at its regular meetings, or when the PJM Board so requires, an account of his or her transactions as Treasurer and of the financial condition of the LLC. If required by the Board, the Treasurer shall give the LLC a bond (which shall be renewed periodically) in such sum and with such surety or sureties as shall be satisfactory to the PJM Board for the faithful performance of the duties of his office and of the restoration to the LLC, in case of his or her death, resignation, retirement or removal from office, of all books, papers, vouchers, money and other property of whatever kind in his or her possession or under his or her control belonging to the LLC.

9.5 Renewal of Officers; Vacancies.

Any officer elected or appointed by the PJM Board may be removed at any time by the affirmative vote of a majority of the PJM Board eligible to vote. Any vacancy occurring in any office of the LLC shall be filled by the PJM Board.

9.6 Compensation.

The salaries of all officers and agents of the LLC, and the reasonable compensation of the PJM Board, shall be fixed by the PJM Board.

10. OFFICE OF THE INTERCONNECTION

10.1 Establishment.

The Office of the Interconnection shall implement this Agreement, administer the PJM Tariff, and undertake such other responsibilities as set forth herein. All personnel of the Office of the Interconnection shall be employees of the LLC or under contract thereto. The cost of the Office of the Interconnection and expenses associated therewith, including salaries and expenses of said personnel, space and any necessary facilities or other capital expenditures, shall be recovered in accordance with Schedule 3. The Office of the Interconnection shall adopt, publish and comply with standards of conduct that satisfy the regulations of FERC.

10.2 Processes and Organization.

In order to carry out the responsibilities of the Office of the Interconnection for the safe and reliable operation of the PJM Region, the President may establish processes and organization for operating personnel and facilities as the President shall deem appropriate, and shall request such Members as the President shall deem appropriate to participate in such processes and organization. All such processes and organization shall be carried out in accordance with all applicable code of conduct or other functional separation requirements of FERC.

10.3 Confidential Information.

The Office of the Interconnection shall comply with the requirements of Section 18.17 with respect to any proprietary or confidential information received from or about any Member.

10.4 Duties and Responsibilities.

The Office of the Interconnection, under the direction of the President as supervised and overseen by the PJM Board, shall carry out the following duties and responsibilities, in accordance with the provisions of this Agreement:

i) Administer and implement this Agreement;

i) Perform such functions in furtherance of this Agreement as the PJM Board, acting within the scope of its duties and responsibilities under this Agreement, may direct;

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iii) Prepare, maintain, update and disseminate the PJM Manuals;

iv) Comply with NERC, and Applicable Regional Reliability Council operation and planning standards, principles and guidelines;

v) Maintain an appropriately trained workforce, and such equipment and facilities, including computer hardware and software and backup power supplies, as necessary or appropriate to implement or administer this Agreement;

vi) Direct the operation and coordinate the maintenance of the facilities of the PJM Region used for both load and reactive supply, so as to maintain reliability of service and obtain the benefits of pooling and interchange consistent with this Agreement, the Reliability Assurance Agreement, and the Reliability Assurance Agreement-West;

vii) Direct the operation and coordinate the maintenance of the bulk power supply facilities of the PJM Region with such facilities and systems of others not party to this Agreement in accordance with agreements between the LLC and such other systems to secure reliability and continuity of service and other advantages of pooling on a regional basis;

viii) Perform interchange accounting and maintain records pertaining to the operation of the PJM Interchange Energy Market and the PJM Region;

ix) Notify the Members of the receipt of any application to become a Member, and of the action of the Office of the Interconnection on such application, including but not limited to the completion of integration of a new Members system into the PJM Region, as specified in Section 11.6(f);

x Calculate the Weighted Interest and Default Allocation Assessment of each Member;
)

x Maintain accurate records of the sectors in which each Voting Member is entitled to vote, and calculate the results of any vote
i taken in the Members Committee;
)

x Furnish appropriate information and reports as are required to keep the Members regularly informed of the outlook for, the
i functioning of, and results achieved by the PJM Region;
i
)

xii File with FERC on behalf of the Members any amendments to this Agreement or the Schedules hereto, any new Schedules
i) hereto, and make any other regulatory filings on behalf of the Members or the LLC necessary to implement this Agreement;

x At the direction of the PJM Board, submit comments to regulatory authorities on matters pertinent to the PJM Region;
i
v
)

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xv) Consult with the standing or other committees established pursuant to Section 8.6(a) on matters within the responsibility of the committee;

xvi) Perform operating studies of the bulk power supply facilities of the PJM Region and make such recommendations and initiate such actions as may be necessary to maintain reliable operation of the PJM Region;

xvii) Accept, on behalf of the Members, notices served under this Agreement;

xviii) Perform those functions and undertake those responsibilities transferred to it under the East Transmission Owners Agreement and West Transmission Owners Agreement, including (A) direct the operation of the transmission facilities of the parties to the East Transmission Owners Agreement (B) direct the operation of the transmission facilities of the Parties to the West Transmission Owners Agreement, (C) administer the PJM Tariff, and (D) administer the Regional Transmission Expansion Planning Protocol set forth as Schedule 6 to this Agreement;

xix) Perform those functions and undertake those responsibilities transferred to it under the Reliability Assurance Agreement, as specified in Schedule 8 of this Agreement, and those functions and responsibilities transferred to it under the Reliability Assurance Agreement-West, as specified in Schedule 8A of this Agreement;

xx) Monitor the operation of the PJM Region, ensure that appropriate Emergency plans are in place and appropriate Emergency drills are conducted, declare the existence of an Emergency, and direct the operations of the Members as necessary to manage, alleviate or end an Emergency;

xxi) Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices; and

xxi Initiate such legal or regulatory proceedings as directed by the PJM Board to enforce the obligations of this Agreement.
i)

11. MEMBERS

11.1 Management Rights.

The Members or any of them shall not take part in the management of the business of, and shall not transact any business for, the LLC in their capacity as Members, nor shall they have power to sign for or to bind the LLC.

11.2 Other Activities.

Except as otherwise expressly provided herein, any Member may engage in or possess any interest in another business or venture of any nature and description, independently or with others, even if such activities compete directly with the business of the LLC, and neither the LLC nor any Member hereof shall have any rights in or to any such independent ventures or the income or profits derived therefrom.

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11.3 Member Responsibilities.

11.3.1 General.

To facilitate and provide for the work of the Office of the Interconnection and of the several committees appointed by the Members Committee, each Member shall, to the extent applicable;

(a) Maintain adequate records and, subject to the provisions of this Agreement for the protection of the confidentiality of proprietary or commercially sensitive information, provide data required for (i) coordination of operations, (ii) accounting for all interchange transactions, (iii) preparation of required reports, (iv) coordination of planning, including those data required for capacity accounting under the Reliability Assurance Agreement and Reliability Assurance Agreement-West; (v) preparation of maintenance schedules, (vi) analysis of system disturbances, and (vii) such other purposes, including those set forth in Schedule 2, as will contribute to the reliable and economic operation of the PJM Region;

(b) Provide such recording, telemetering, revenue quality metering, communication and control facilities as are required for the coordination of its operations with the Office of the Interconnection and those of the other Members and to enable the Office of the Interconnection to operate the PJM Region and otherwise implement and administer this Agreement, including equipment required in normal and Emergency operations and for the recording and analysis of system disturbances;

(c) Provide adequate and properly trained personnel to (i) permit participation in the coordinated operation of the PJM Region, (ii) meet its obligation on a timely basis for supply of records and data, (iii) serve on committees and participate in their investigations, and (iv) share in the representation of the Interconnection in inter-regional and national reliability activities;

(d) Share in the costs of committee activities and investigations (including costs of consultants, computer time and other appropriate items), communication facilities used by all the Members (in addition to those provided in the Office of the Interconnection), and such other expenses as are approved for payment by the PJM Board, such costs to be recovered as provided in Schedule 3;

(e) Comply with the requirements of the PJM Manuals and all directives of the Office of the Interconnection to take any action for the purpose of managing, alleviating or ending an Emergency, and authorize the Office of the Interconnection to direct the transfer or interruption of the delivery of energy on their behalf to meet an Emergency and to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, and be subject to the emergency procedure charges specified in Schedule 9 of this Agreement for any failure to follow the Emergency instructions of the Office of the Interconnection.

11.3.2 Facilities Planning and Operation.

Consistent with and subject to the requirements of this Agreement, the PJM Tariff, the governing agreements of the Applicable Regional Reliability Councils, the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, the West Transmission Owners Agreement, the East Transmission Owners Agreement, and the PJM Manuals, each Member shall cooperate with the other Members in the coordinated planning and operation of the facilities of its System within the PJM Region so as to obtain the greatest practicable degree of reliability, compatible economy and other advantages from such coordinated planning and operation. In furtherance of such cooperation each Member shall, as applicable:

(a) Consult with the other Members and the Office of the Interconnection, and coordinate the installation of its electric generation and Transmission Facilities with those of such other Members so as to maintain reliable service in the PJM Region;

(b) Coordinate with the other Members, the Office of the Interconnection and with others in the planning and operation of the regional facilities to secure a high level of reliability and continuity of service and other advantages;

(c) Cooperate with the other Members and the Office of the Interconnection in the implementation of all policies and procedures established pursuant to this Agreement for dealing with Emergencies, including but not limited to policies and procedures for maintaining or arranging for a portion of a Members Capacity Resources, at least equal to the applicable levels established from time to time by the Office of the Interconnection, to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

(d) Cooperate with the members of Applicable Regional Reliability Councils to augment the reliability of the bulk power supply facilities of the region and comply with Applicable Regional Reliability Councils and NERC operating and planning standards, principles and guidelines and the PJM Manuals;

(e) Obtain or arrange for transmission service as appropriate to carry out this Agreement;

(f) Cooperate with the Office of the Interconnections coordination of the operating and maintenance schedules of the Members generating and Transmission Facilities with the facilities of other Members to maintain reliable service to its own customers and those of the other Members and to obtain economic efficiencies consistent therewith;

(g) Cooperate with the other Members and the Office of the Interconnection in the analysis, formulation and implementation of plans to prevent or eliminate conditions that impair the reliability of the PJM Region; and

(h) Adopt and apply standards adopted pursuant to this Agreement and conforming to NERC, and Applicable Regional Reliability Council standards, principles and guidelines and the PJM Manuals, for system design, equipment ratings, operating practices and maintenance practices.

11.3.3 Electric Distributors.

In addition to any of the foregoing responsibilities that may be applicable, each Member that is an Electric Distributor, whether or not that Member votes in the Members Committee in the Electric Distributor sector or meets the eligibility requirements for any other sector of the Members Committee, shall:

(a) Accept, comply with or be compatible with all standards applicable within the PJM Region with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals, or be subject to an interconnected Members requirements relating to the foregoing, so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region;

(b) Assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting automatically or manually with the Office of the Interconnection as it directs the operation of the PJM Region;

(c) Maintain or arrange for a portion of its connected load to be subject to control by automatic underfrequency, under-voltage, or other load-shedding devices at least equal to the levels established pursuant to the Reliability Assurance Agreement and Reliability Assurance Agreement-West, as applicable, or be subject to another Members control for these purposes;

(d) Provide or arrange for sufficient reactive capability and voltage control facilities to conform to Good Utility Practice and (i) to meet the reactive requirements of its system and customers and (ii) to maintain adequate voltage levels and the stability required by the bulk power supply facilities of the PJM Region;

(e) Shed connected load, share Capacity Resources, initiate active load management programs, and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in Emergencies;

(f) Maintain or arrange for a portion of its Capacity Resources at least equal to the level established pursuant to the Reliability Assurance Agreement to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

(g) Provide or arrange through another Member for the services of a 24-hour local control center to coordinate with the Office of the Interconnection, each such control center to be furnished with appropriate telemetry equipment as specified in the PJM Manuals, and to be staffed by system operators trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner;

(h) Provide to the Office of the Interconnection all System, accounting, customer tracking, load forecasting (including all load to be served from its System) and other data necessary or appropriate to implement or administer this Agreement, the Reliability Assurance Agreement and the Reliability Assurance Agreement-West; and

(i) Comply with the underfrequency relay obligations and charges specified in Schedule 7 of this Agreement.

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	Vice President, Government Policy		
IssuedOn:	April 30, 2004		

11.3.4 Reports to the Office of the Interconnection.

Each Member shall report as promptly as possible to the Office of the Interconnection any changes in its operating practices and procedures relating to the reliability of the bulk power supply facilities of the PJM Region. The Office of the Interconnection shall review such reports, and if any change in an operating practice or procedure of the Member is not in accord with the established operating principles, practices and procedures for the PJM Region and such change adversely affects such region and regional reliability, it shall so inform such Member, and the other Members through their representative on the Operating Committee, and shall direct that such change be modified to conform to the established operating principles, practices and procedures.

11.4 Regional Transmission Expansion Planning Protocol.

The Members shall participate in regional transmission expansion planning in accordance with the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 to this Agreement.

11.5 Member Right to Petition.

(a) Nothing herein shall deprive any Member of the right to petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the petitioning Member believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any other Member (a) to oppose said proposal, or (b) to withdraw from the LLC pursuant to Section 4.1.

(b) Nothing herein shall be construed as affecting in any way the right of the Members, acting pursuant to a vote of the Members Committee as specified in Section 8.4, unilaterally to make an application to FERC for a change in any rate, charge, classification, tariff or service, or any rule or regulation related thereto, under section 205 of the Federal Power Act and pursuant to the rules and regulations promulgated by FERC thereunder, subject to the right of any Member that voted against such change in any rate, charge, classification, tariff or service, or any rule or regulation related thereto, in intervene in opposition to any such application.

11.6 Membership Requirements.

(a) To qualify as a Member, an entity shall:

i) Be a Transmission Owner a Generation Owner, an Other Supplier, an Electric Distributor, or an End-Use Customer; and

ii) Accept the obligations set forth in this Agreement.

(b) Certain Members that are Load Serving Entities are parties to the Reliability Assurance Agreement or Reliability Assurance Agreement-West. Upon becoming a Member, any entity that is a Load Serving Entity in the PJM Control Area and that wishes to become a Market Buyer shall also simultaneously execute the Reliability Assurance Agreement. Any entity that is a

Load Serving Entity in the PJM West Region and that wishes to become a Market Buyer shall also simultaneously execute the Reliability Assurance Agreement-West.

(c) An entity that wishes to become a party to this Agreement shall apply, in writing, to the President setting forth its request, its qualifications for membership, its agreement to supply data as specified in this Agreement, its agreement to pay all costs and expenses in accordance with Schedule 3, and providing all information specified pursuant to the Schedules to this Agreement for entities that wish to become Market Participants. Any such application that meets all applicable requirements shall be approved by the President within sixty (60) days.

(d) Nothing in this Section 11 is intended to remove, in any respect, the choice of participation by other utility companies or organizations in the operation of the PJM Region through inclusion in the System of a Member.

(e) An entity whose application is accepted by the President pursuant to Section 11.6(c) shall execute a supplement to this Agreement in substantially the form prescribed in Schedule 4, which supplement shall be countersigned by the President. The entity shall become a Member effective on the date the supplement is countersigned by the President.

(f) Entities whose applications contemplate expansion or rearrangement of the PJM Region may become Members promptly as described in Sections 11.6(c) and 11.6(e) above, but the integration of the applicants system into all of the operation and accounting provisions of this Agreement and the Reliability Assurance Agreement, or, as applicable, the Reliability Assurance Agreement-West, shall occur only after completion of all required installations and modifications of metering, communications, computer programming, and other necessary and appropriate facilities and procedures, as determined by the Office of the Interconnection. The Office of the Interconnection shall notify the other Members when such integration has occurred.

(g) Entities that become Members will be listed in Schedule 12 of this Agreement.

(h) In accordance with the MAAC Agreement, a Member serving load in the MAAC Control Zone shall be a member of MAAC and any other Member may be a member of MAAC.

12. TRANSFERS OF MEMBERSHIP INTEREST

The rights and obligations created by this Agreement shall inure to and bind the successors and assigns of such Member; provided, however, that the rights and obligations of any Member hereunder shall not be assigned without the approval of the Members Committee except as to a successor in operation of a Members electric operating properties by reason of a merger, consolidation, reorganization, sale, spinoff, or foreclosure, as a result of which substantially all such electric operating properties are acquired by such a successor, and such successor becomes a Member.

13. INTERCHANGE

13.1 Interchange Arrangements with Non-Members.

Any Member may enter into interchange arrangements with others that are not Members with respect to the delivery or receipt of capacity and energy to fulfill its obligations hereunder or for any other purpose, subject to the standards and requirements established in or pursuant to this Agreement.

13.2 Energy Market.

The Office of the Interconnection shall administer an efficient energy market within the PJM Region, to be known as the PJM Interchange Energy Market, in which Members may buy and sell energy. The Office of the Interconnection will schedule in advance and dispatch generation on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by sellers within and into the PJM Region, continuing until sufficient generation is dispatched to serve the energy purchase requirements of such region and buyers out of such region, as well as the requirements of the PJM Region for ancillary services provided by such generation. Scheduling and dispatch shall be conducted in accordance with applicable schedules to the PJM Tariff and the Schedules to this Agreement.

14. METERING

14.1 Installation, Maintenance and Reading of Meters.

The quantities of electric energy involved in determination of the amounts of the billing rendered hereunder shall be ascertained by means of meters installed, maintained and read either at the expense of the party on whose premises the meters are located or as otherwise provided for by agreement between the parties concerned.

14.2 Metering Procedures.

Procedures with respect to maintenance, testing, calibrating, correction and registration records, and precision tolerance of all metering equipment shall be in accordance with Good Utility Practice. The expense of testing any meter shall be borne by the party owning such meter, except that when a meter tested upon request of another party is found to register within the established tolerance the party making the request shall bear the expense of such test.

14.3 Integrated Megawatt-Hours.

All metering of energy required herein shall be the integration of megawatt hours in the clock hour, and the quantities thus obtained shall constitute the megawatt load for such clock hour; provided, however, that adjustment shall be made for other contractual obligations of any Member as may be required to determine the quantity to be accounted for hereunder, and for transmission losses.

14.4 Meter Locations.

The meter locations to be used by the Members in determining their energy transactions on the PJM Region shall be as reasonably determined from time to time by the Member or the Office of the Interconnection.

14.5 Metering of Behind The Meter Generation.

Behind The Meter Generation consisting of one or more generating units individually rated at ten megawatts or greater or that otherwise have been identified by the Office of the Interconnection as requiring metering for operational security reasons must have both revenue quality metering and telemetry equipment for operational security purposes. Behind The Meter Generation consisting of multiple generating units that are individually rated less than ten megawatts but together total more than ten megawatts and are identified by the Office of the Interconnection as requiring revenue quality metering and telemetry equipment may meet these metering requirements by being metered as a single unit.

15. ENFORCEMENT OF OBLIGATIONS

15.1 Failure to Meet Obligations.

15.1.1 Termination of Market Buyer Rights.

The Office of the Interconnection shall terminate a Market Buyers right to make purchases from the PJM Interchange Energy Market, the PJM Capacity Credit Market or any other market operated by PJM if it determines that the Market Buyer does not continue to meet the obligations set forth in this Agreement, including but not limited to the obligation to be in compliance with PJMs creditworthiness requirements and the obligation to make timely payment, provided that the Office of the Interconnection has notified the Market Buyer of any such deficiency and afforded the Market Buyer a reasonable opportunity to cure pursuant to Section 15.1.3. The Office of the Interconnection shall reinstate a Market Buyers right to make purchases from the PJM Interchange Energy Market and PJM Capacity Credit Market upon demonstration by the Market Buyer that it has come into compliance with the obligations set forth in this Agreement.

15.1.2 Termination of Market Seller Rights.

The Office of the Interconnection shall not accept offers from a Market Seller that has not complied with the prices, terms, or operating characteristics of any of its prior scheduled transactions in the PJM Interchange Energy Market, unless such Market Seller has taken appropriate measures to the satisfaction of the Office of the Interconnection to ensure future compliance.

15.1.3 Payment of Bills.

(a) A Member shall make full and timely payment, in accordance with the terms specified by the Office of the Interconnection, of all bills rendered in connection with or arising under or from this Agreement, any service or rate schedule, any tariff, or any services performed by the Office of the Interconnection, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. With respect to any payment that the LLC is required to make to a Member in connection with or arising under this Agreement, any service or rate schedule, or any tariff, the LLC shall have a right of setoff equal to any amount that the Member is required to pay the LLC in connection with or arising under or from this Agreement, any service or rate schedule, any tariff, or any services performed by the Office of the Interconnection. Any Member that fails to make full and timely payment to the LLC, or otherwise fails to meet its financial or other obligations to a Member, the Office of the Interconnection or the LLC under this Agreement, shall, in addition to any requirement set forth in Sections 15.1.1 and 15.1.2 and upon expiration of the 3-day period specified below be in default. If the Office of the Interconnection concludes, upon its own initiative or the recommendation of or complaint by the Members Committee or any Member, that a Member is in breach of any obligation under this Agreement, including, but not limited to, the obligation to make timely payment and the obligation to meet PJMs creditworthiness standards and to otherwise comply with PJMs credit policies, the Office of the Interconnection shall so notify such Member and inform all other Members. The notified Member may remedy such asserted breach by: (i) paying all amounts assertedly due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERCs regulations at 18 C.F.R. 35.19a(a)(2)(iii); and (ii) demonstration to the satisfaction of the Office of the Interconnection that the Member has taken appropriate measures to meet any other obligation of which it was deemed to be in breach; provided, however, that any such payment or demonstration may be subject to a reservation of rights, if any, to subject such matter to the PJM Dispute Resolution Procedures; and provided, further, that any such determination by the Office of the Interconnection may be subject to review by the PJM Board upon request of the Member involved or the Office of the Interconnection. If a Member has not remedied a breach by the 3rd business day following receipt of the Office of the Interconnections notice, or receipt of the PJM Boards decision on review, if applicable, then the Member shall be in default and, in addition to such other remedies as may be available to the LLC:

i) A defaulting Market Participant shall be precluded from buying or selling in the PJM Interchange Energy Market, the PJM Capacity Credit Market, or any other market operated by PJM until the default is remedied as set forth above;

ii) A defaulting Member shall not be entitled to participate in the activities of any committee or other body established by the Members Committee or the Office of the Interconnection; and

iii) A defaulting Member shall not be entitled to vote on the Members Committee or any other committee or other body established pursuant to this Agreement.

15.2 Enforcement of Obligations.

If the Office of the Interconnection sends a notice to the PJM Board that a Member has failed to perform an obligation under this Agreement, the PJM Board shall initiate such action against such Member to enforce such obligation as the PJM Board shall deem appropriate. Subject to the procedures specified in Section 15.1, a Members failure to perform such obligation shall be deemed to be a default under this Agreement. In order to remedy a default, but without limiting any rights the LLC may have against the defaulting Member, the PJM Board may assess against, and collect from, the Members not in default, in proportion to their Default Allocation Assessment, an amount equal to the amount that the defaulting Member has failed to pay to the Office of the Interconnection, along with appropriate interest. Such assessment shall in no way relieve the defaulting Member of its obligations. A Member that has paid such an assessment to the LLC shall have an independent right to seek and obtain payment and recovery from the defaulting Member of the amount of the assessment the Member paid to the LLC. In addition to any amounts in default, the defaulting Member shall be liable to the LLC for all reasonable costs incurred in enforcing the defaulting Members obligations.

15.2.1 Collection by the Office of the Interconnection.

By vote at any Members Committee meeting, a majority of the Members that have paid a Default Allocation Assessment may request and appoint the Office of the Interconnection to act as agent on behalf of the Members that have paid a Default Allocation Assessment, solely for the purpose of pursuing and collecting any amounts so assessed; provided, however, that any Member that does not desire for the Office of the Interconnection to act on their behalf with regard to such collection shall so inform the Office of the Interconnection. In the event that the Office of the Interconnection is appointed as agent for the Members, the Office of the Interconnection shall be authorized to pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims on behalf of the affected Members in the state and federal courts as well as under the United States Bankruptcy Code; provided, however, that the Office of the Interconnection shall take no action on behalf of those Members that have requested that the Office of the Interconnection not act on their behalf. After deducting the costs of collection, any amounts recovered by the Office of the Interconnection on behalf of the affected Members shall be distributed to the Members who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Member except those Members who informed the Office of the Interconnection that it should not act as their agent.

15.2.2 Default Allocation Assessment.

(a) Default Allocation Assessment shall be equal to (0.1(1/N) + 0.9(A/Z)), where:

N = the total number of Members, calculated as of five oclock p.m. eastern prevailing time on the date PJM declares a Member in default, excluding *ex officio* Members, State Consumer Advocates, Emergency and Economic Load Response Program Special Members, and municipal electric system Members that have been granted a waiver under section 17.2 of this Agreement.

A = for Members comprising factor N above, the Members gross activity as determined by summing the absolute values of the charges and credits for each of the Activity Line Items identified in section 15.2.2(b) of this Agreement as accounted for and billed pursuant to section 3 of Schedule 1 of this Agreement for the month of default and the two previous months.

Z = the sum of factor A for all Members excluding *ex officio* Members, State Consumer Advocates, Emergency and Economic Load Response Program Special Members, and municipal electric system Members that have been granted a waiver under section 17.2 of this Agreement.

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The assessment value of (0.1(1/N)) shall not exceed $10,000 per Member per calendar year, cumulative of all defaults. If one or more defaults arise that cause the value to exceed $10,000 per Member, then the excess shall be reallocated through the gross activity factor.

(b) Activity Line Items shall be each of the line items on the PJM monthly bills net of load reconciliation adjustments and adjustments applicable to activity for the current billing month appearing on the same bill.

15.3 Obligations to a Member in Default.

The Members have no continuing obligation to provide the benefits of interconnected operations to a Member in default.

15.4 Obligations of a Member in Default.

A Member found to be in default shall take all possible measures to mitigate the continued impact of the default on the Members not in default, including, but not limited to, loading its own generation to supply its own load to the maximum extent possible.

15.5 No Implied Waiver.

A failure of a Member, the PJM Board, or the LLC to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such entitys right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

16. LIABILITY AND INDEMNITY

16.1 Members.

(a) As between the Members, except as may be otherwise agreed upon between individual Members with respect to specified interconnections, each Member will indemnify and hold harmless each of the other Members, and its directors, officers, employees, agents, or representatives, of and from any and all damages, losses, claims, demands, suits, recoveries, costs and expenses (including all court costs and reasonable attorneys fees), caused by reason of bodily injury, death or damage to property of any third party, resulting from or attributable to the fault, negligence or willful misconduct of such Member, its directors, officers, employees, agents, or representatives, or resulting from, arising out of, or in any way connected with the performance of its obligations under this Agreement, excepting only, and to the extent, such cost, expense, damage, liability or loss may be caused by the fault, negligence or willful misconduct of any other Member. The duty to indemnify under this Agreement will continue in full force and effect notwithstanding the expiration or termination of this Agreement or the withdrawal of a Member from this Agreement, with respect to any loss, liability, damage or other expense based on facts or conditions which occurred prior to such termination or withdrawal.

(b) The amount of any indemnity payment arising hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Member seeking indemnification in respect of the indemnified action, claim, demand, costs, damage or liability. If any Member shall have received an indemnity payment for an action, claim, demand, cost, damage or liability and shall subsequently actually receive insurance proceeds or other amounts for such action, claim, demand, cost, damage or liability, then such Member shall pay to the Member that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

16.2 LLC Indemnified Parties.

(a) The LLC will indemnify and hold harmless the PJM Board, the LLCs officers, employees and agents, and any representatives of the Members serving on the Members Committee and any other committee created under Section 8 of this Agreement (all such Board Members, officers, employees, agents and representatives for purposes of this Section 16 being referred to as LLC Indemnified Parties), of and from any and all actions, claims, demands, costs (including consequential or indirect damages, economic losses and all court costs and reasonable attorneys fees) and liabilities to any third parties, arising from, or in any way connected with, the performance of the LLC under this Agreement, or the fact that such LLC Indemnified Party was serving in such capacity, except to the extent that such action, claim, demand, cost or liability results from the willful misconduct of any LLC Indemnified Party with respect to participation in the misconduct. To the extent any dispute arises between any Member and the LLC arising from, or in any way connected with, the performance of the LLC under this Agreement, the Member and the LLC shall follow the PJM Dispute Resolution Procedures. To the extent that any such action, claim, demand, cost or liability arises from a Members contractual or other obligation to provide electric service directly or indirectly to said third party, which obligation to provide service is limited by the terms of any tariff, service agreement, franchise, statute, regulatory requirement, court decision or other limiting provision, the Member designates the LLC and each LLC Indemnified Party a beneficiary of said limitation.

(b) An LLC Indemnified Party shall not be personally liable for monetary damages for any breach of fiduciary duty by such LLC Indemnified Party, except that an LLC Indemnified Party shall be liable to the extent provided by applicable law (i) for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law, or (ii) for any transaction from which the LLC Indemnified Party derived an improper personal benefit. Notwithstanding (i) and (ii), indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the LLC if and to the extent that the court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses that such court shall deem proper. If applicable law is hereafter construed or amended to authorize the further elimination or limitation of the liability of LLC Indemnified Parties, then the liability of the LLC Indemnified Parties, in addition to the limitation on personal liability provided herein, shall be limited to the fullest extent permitted by law. No amendment to or repeal of this section shall apply to or have any effect on the liability or alleged liability of any LLC Indemnified Party or with respect to any acts or omissions occurring prior to such amendment or repeal. The termination of any action, suit or proceeding by judgment, order, settlement, conviction, or upon a plea of *nolo contendere* or its equivalent, shall not, of itself, create a presumption that the person did not act in good faith and in a manner which such person reasonably believed to be in or not opposed to the best interests of the LLC, and with respect to any criminal action or proceeding, had reasonable cause to believe that his or her conduct was unlawful.

(c) The LLC may pay expenses incurred by an LLC Indemnified Party in defending a civil, criminal, administrative or investigative action, suit or proceeding in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of such LLC Indemnified Party to repay such amount if it shall ultimately be determined that such LLC Indemnified Party is not entitled to be indemnified by the LLC as authorized in this Section.

(d) In the event the LLC incurs liability under this Section 16.2 that is not adequately covered by insurance, such amounts shall be recovered pursuant to the PJM Tariff as provided in Schedule 3 of this Agreement.

16.3 Workers Compensation Claims.

Each Member shall be solely responsible for all claims of its own employees, agents and servants growing out of any Workers Compensation Law.

16.4 Limitation of Liability.

No Member or its directors, officers, employees, agents, or representatives shall be liable to any other Member or its directors, officers, employees, agents, or representatives, whether liability arises out of contract, tort (including negligence), strict liability, or any other cause of or form of action whatsoever, for any indirect, incidental, consequential, special or punitive cost, expense, damage or loss, including but not limited to loss of profits or revenues, cost of capital of financing, loss of goodwill or cost of replacement power, arising from such Members performance or failure to perform any of its obligations under this Agreement or the ownership, maintenance or operation of its System; provided, however, that nothing herein shall be deemed to reduce or limit the obligations of any Member with respect to the claims of persons or entities that are not parties to this Agreement.

16.5 Resolution of Disputes.

To the extent any dispute arises between one or more Members regarding any issue covered by this Agreement, the Members shall follow the dispute resolution procedures set forth in the PJM Dispute Resolution Procedures.

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16.6 Gross Negligence or Willful Misconduct.

Neither the LLC nor the LLC Indemnified Parties shall be liable to the Members or any of them for any claims, demands or costs arising from, or in any way connected with, the performance of the LLC under this Agreement other than actions, claims or demands based on gross negligence or willful misconduct; provided, however, that nothing herein shall limit or reduce the obligations of the LLC to the Members or any of them under the express terms of this Agreement or the PJM Tariff, including, but not limited to, those set forth in Sections 6.2 and 6.3 of this Agreement.

16.7 Insurance.

The PJM Board shall be authorized to procure insurance against the risks borne by the LLC and the LLC Indemnified Parties, the cost of which shall be treated as a cost and expense of the LLC.

17. MEMBER REPRESENTATIONS, WARRANTIES AND COVENANTS

17.1 Representations and Warranties.

Each Member makes the following representations and warranties to the LLC and each other Member, as of the Effective Date or such later date as such Member shall become admitted as a Member of the LLC.

17.1.1 Organization and Existence.

Such Member is an entity duly organized, validly existing and in good standing under the laws of the state of its organization.

17.1.2 Power and Authority.

Such Member has the full power and authority to execute, deliver and perform this Agreement and to carry out the transactions contemplated hereby.

17.1.3 Authorization and Enforceability.

The execution and delivery of this Agreement by such Member and the performance of its obligations hereunder have been duly authorized by all requisite action on the part of the Member, and do not conflict with any applicable law or with any other agreement binding upon the Member. The Agreement has been duly executed and delivered by such Member and constitutes the legal, valid and binding obligation of such Member, enforceable against it in accordance with the terms thereof, except insofar as such enforceability may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditors rights generally, and to general principles of equity whether such principles are considered in proceedings in law or in equity.

17.1.4 No Government Consents.

No authorization, consent, approval or order of, notice to or registration, qualification, declaration or filing with, any governmental authority is required for the execution, delivery and performance by such Member of this Agreement or the carrying out by such Member of the transactions contemplated hereby other than such authorization, consent, approval or order of, notice to or registration, qualification, declaration or filing that is pending before such governmental authority.

17.1.5 No Conflict or Breach.

None of the execution, delivery and performance by such Member of this Agreement, the compliance with the terms and provisions hereof and the carrying out of the transactions contemplated hereby, conflicts or will conflict with or will result in a breach or violation of any of the terms, conditions or provisions of any law, governmental rule or regulation or the charter documents or bylaws of such Member or any applicable order, writ, injunction, judgment or decree of any court or governmental authority against such Member or by which it or any of its properties, is bound, or any loan agreement, indenture, mortgage, bond, note, resolution, contract or other agreement or instrument to which such Member is a party or by which it or any of its properties is bound, or constitutes or will constitute a default thereunder or will result in the imposition of any lien upon any of its properties.

17.1.6 No Proceedings.

There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Member, threatened against the Member before any federal, state, foreign or local court, tribunal or government agency or authority that might materially delay, prevent or hinder the performance by the Member of its obligations hereunder.

17.2 Municipal Electric Systems.

Any provisions of Section 17.1 notwithstanding, if any Member that is a municipal electric system believes in good faith that the provisions of Sections 5.1(b) and 16.1 of this Agreement may not lawfully be applied to that Member under applicable state law governing municipal activities, the Member may request a waiver of the pertinent provisions of the Agreement. Any such request for waiver shall be supported by an opinion of counsel for the Member to the effect that the provision of the Agreement as to which waiver is sought may not lawfully be applied to the Member under applicable state law. The PJM Board shall have the right to have the opinion of the Members counsel reviewed by counsel to the LLC. If the PJM Board concludes that either or both of Sections 5.1(b) and 16.1 of this Agreement may not lawfully be applied to a municipal electric system Member, it shall waive the application of the affected provision or provisions to such municipal Member. Any Member not permitted by law to indemnify the other Members shall not be indemnified by the other Members.

17.3 Survival.

All representations and warranties contained in this Section 17 shall survive the execution and delivery of this Agreement.

18. MISCELLANEOUS PROVISIONS

18.1 [Reserved.]

18.2 Fiscal and Taxable Year.

The fiscal year and taxable year of the LLC shall be the calendar year.

18.3 Reports.

Each year prior to the Annual Meeting of the Members, the PJM Board shall cause to be prepared and distributed to the Members a report of the LLCs activities since the prior report.

18.4 Bank Accounts; Checks, Notes and Drafts.

(a) Funds of the LLC shall be deposited in an account or accounts of a type, in form and name and in a bank(s) or other financial institution(s) which are participants in federal insurance programs as selected by the PJM Board. The PJM Board shall arrange for the appropriate conduct of such accounts. Funds may be withdrawn from such accounts only for *bona fide* and legitimate LLC purposes and may from time to time be invested in such short-term securities, money market funds, certificates of deposit or other liquid assets as the PJM Board deems appropriate. All checks or demands for money and notes of the LLC shall be signed by any officer or by any other person designated by the PJM Board.

(b) The Members acknowledge that the PJM Board may maintain LLC funds in accounts, money market funds, certificates of deposit, other liquid assets in excess of the insurance provided by the Federal Deposit Insurance Corporation, or other depository insurance institutions and that the PJM Board shall not be accountable or liable for any loss of such funds resulting from failure or insolvency of the depository institution.

(c) Checks, notes, drafts and other orders for the payment of money shall be signed by such persons as the PJM Board from time to time may authorize. When the PJM Board so authorizes, the signature of any such person may be a facsimile.

18.5 Books and Records.

(a) At all times during the term of the LLC, the PJM Board shall keep, or cause to be kept, full and accurate books of account, records and supporting documents, which shall reflect, completely, accurately and in reasonable detail, each transaction of the LLC. The books of account shall be maintained and tax returns prepared and filed on the method of accounting determined by the PJM Board. The books of account, records and all documents and other writings of the LLC shall be kept and maintained at the principal office of the Interconnection.

(b) The PJM Board shall cause the Office of the Interconnection to keep at its principal office the following:

i) A current list in alphabetical order of the full name and last known business address of each Member and the Members Committee sector of each Voting Member;

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IssuedOn:	November 1, 2004		

iA copy of the Certificate of Formation and the Certificate of Conversion, and all Certificates of Amendment thereto;
i
)

i Copies of the LLCs federal, state, and local income tax returns and reports, if any, for the three most recent years; and
i
i
)

iCopies of the Operating Agreement, as amended, and of any financial statements of the LLC for the three most recent years.
\
)

18.6 Amendment.

(a) Except as provided by law or otherwise set forth herein, this Agreement, including any Schedule hereto, may be amended, or a new Schedule may be created, only upon: (i) submission of the proposed amendment to the PJM Board for its review and comments; (ii) approval of the amendment or new Schedule by the Members Committee, after consideration of the comments of the PJM Board, in accordance with Section 8.4, or written agreement to an amendment of all Members not in default at the time the amendment is agreed upon; and (iii) approval and/or acceptance for filing of the amendment by FERC and any other regulatory body with jurisdiction thereof as may be required by law. If and as necessary, the Members Committee may file with FERC or other regulatory body of competent jurisdiction any amendment to this Agreement or to its Schedules or a new Schedule not filed by the Office of the Interconnection.

(b) Notwithstanding the foregoing, an applicant eligible to become a Member in accordance with the procedures specified in this Agreement shall become a Member by executing a counterpart of this Agreement without the need for amendment of this Agreement or execution of such counterpart by any other Member.

(c) Each of the following fundamental changes to the LLC shall require or be deemed to require an amendment to this Agreement and shall require the prior approval of FERC:

iAdoption of any plan of merger or consolidation;
)

iAdoption of any plan of sale, lease or exchange of assets relating to all, or substantially all, of the property and assets of the
iLLC;
)

iii) Adoption of any plan of division relating to the division of the LLC into two or more corporations or other legal entities;

iv) Adoption of any plan relating to the conversion of the LLC into a stock corporation;

v) Adoption of any proposal of voluntary dissolution; or

vi) Taking any action which has the purpose or effect of the adoption of any plan or proposal described in items (i), (ii), (iii), (iv) or (v) above.

18.7 Interpretation.

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

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18.8 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

18.9 Force Majeure.

No Member shall be liable to any other Member for damages or otherwise be in breach of this Agreement to the extent and during the period such Members performance is prevented by any cause or causes beyond such Members control and without such Members fault or negligence, including but not limited to any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities; provided, however, that any such foregoing event shall not excuse any payment obligation. Upon the occurrence of an event considered by a Member to constitute a force majeure event, such Member shall use due diligence to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that no Member shall be required by this provision to settle any strike or labor dispute.

18.10 Further Assurances.

Each Member hereby agrees that it shall hereafter execute and deliver such further instruments, provide all information and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the terms hereof.

18.11 Seal.

The seal of the LLC shall have inscribed thereon the name of the LLC, the year of its organization and the words Corporate Seal, Delaware. The seal may be used by causing it or a facsimile thereof to be impressed or affixed or reproduced or otherwise.

18.12 Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

18.13 Costs of Meetings.

Each Member shall be responsible for all costs of its representative, alternate or substitute in attending any meeting. The Office of the Interconnection shall pay the other reasonable costs of meetings of the PJM Board and the Members Committee, and such other committees, subcommittees, task forces, working groups, User Groups or other bodies as determined to be appropriate by the Office of the Interconnection, which costs otherwise shall be paid by the

Members attending. The Office of the Interconnection shall reimburse all Board Members for their reasonable costs of attending meetings.

18.14 Notice.

(a) Except as otherwise expressly provided herein, notices required under this Agreement shall be in writing and shall be sent to a Member by overnight courier, hand delivery, telecopier or other reliable electronic means to the representative on the Members Committee of such Member at the address for such Member previously provided by such Member to the Office of the Interconnection. Any such notice so sent shall be deemed to have been given (i) upon delivery if given by overnight couriers or hand delivery, or (ii) upon confirmation if given by telecopier or other reliable electronic means. Notices of meetings of the Members Committee or committees, subcommittees, task forces, working groups and other bodies under its auspices may be given as provided in the Members Committee by-laws.

(b) Notices, as well as copies of the agenda and minutes of all meetings of committees, subcommittees, task forces, working groups, User Groups, or other bodies formed under this Agreement, shall be posted in a timely fashion on and made available for downloading from the PJM website.

18.15 Headings.

The section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

18.16 No Third-Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Members and their respective successors and permitted assigns and, unless expressly stated herein, is not intended to and shall not confer any rights or benefits on any third party (other than successors and permitted assigns) not a signatory hereto.

18.17 Confidentiality.

18.17.1 Party Access.

(a) No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Members confidential data or information.

(b) Except as may be provided in this Agreement or in the PJM Open Access Transmission Tariff, the Office of the Interconnection shall not disclose to its Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Office of the Interconnection or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Office of the Interconnection from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality; provided further that nothing contained herein shall prohibit the Office of the Interconnection from providing Member confidential information to the North American Electric Reliability Council or any of its regional reliability councils to the extent that (i) the Office of the Interconnection determines in its reasonable discretion that the exchange of such information is required to enhance and/or maintain reliability within MAAC and its neighboring reliability councils, (ii) such entity is bound by a written agreement to maintain such confidentiality, and (iii) the Office of the Interconnection has notified the affected party of its intention to release such information no less than five business days prior to the release. The Office of the Interconnection shall collect and use confidential information only in connection with its authority under this Agreement and the Open Access Transmission Tariff and the retention of such information shall be in accordance with PJMs data retention policies.

(c) Nothing contained herein shall prevent the Office of the Interconnection from releasing a Members confidential data or information to a third party provided that the Member has delivered to the Office of the Interconnection specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Office of the Interconnection shall limit the release of a Members confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Office of the Interconnection who shall cease such release as soon as practicable after receipt of such withdrawal notice.

18.17.2 Required Disclosure.

(a) Notwithstanding anything in the foregoing Section to the contrary, and subject to the provisions of Section 18.17.3, if a Member or the Office of the Interconnection is required by applicable law, or in the course of administrative or judicial proceedings other than FERC proceedings or investigations, to disclose to third parties other than the FERC or its staff, information that is otherwise required to be maintained in confidence pursuant to this Agreement, that Member or the Office of the Interconnection may make disclosure of such information; provided, however, that as soon as the Member or the Office of the Interconnection learns of the disclosure requirement and prior to making disclosure, that Member or the Office of the Interconnection shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The disclosing Member and the Office of the Interconnection shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Member and the Office of the Interconnection shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(b) Nothing in this Section 18.17 shall prohibit or otherwise limit the Office of the Interconnections use of information covered herein if such information was: (i) previously known to the Office of the Interconnection without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection using nonconfidential information; (iii) acquired by the Office of the Interconnection from a third party which is not, to the Office of the Interconnections knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section 18.17.

(c) The Office of the Interconnection shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation or administration of this Agreement or of the Open Access Transmission Tariff a contractual duty of confidentiality consistent with this Agreement. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Office of the Interconnection shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

(d) Section 18.17.2(a) does not apply to disclosure of information to the FERC or its staff.

18.17.3 Disclosure to FERC.

Notwithstanding anything in this Section to the contrary, if the FERC or its staff, during the course of an investigation or otherwise, requests information from the Office of the Interconnection that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection shall provide the requested information to the FERC or its staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Office of the Interconnection may, consistent with 18 C.F.R. 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Office of the Interconnection shall notify any affected Member(s) when it is notified by FERC or its staff, that a request for disclosure of, or decision to disclose, confidential information has been received, at which time the Office of Interconnection and the affected Member may respond before such information would be made public, pursuant to 18 C.F.R. 388.112.

18.17.4 Disclosure to Authorized Persons

(a) Notwithstanding anything in this section to the contrary, the Office of the Interconnection and/or the PJM Market Monitor shall disclose confidential information, otherwise required to be maintained in confidence pursuant to this Agreement, to an Authorized Person under the following conditions:

i) The Authorized Person has executed a Non-Disclosure Agreement with the Office of the Interconnection, representing and warranting that he or she: (i) is an Authorized Person; (ii) is duly authorized to enter into and perform the obligations of the Non-Disclosure Agreement; (iii) has adequate procedures to protect against the release of any confidential information received, (iv) is familiar with, and will comply with any applicable procedures of the Authorized Commission which the Authorized Person represents, (v) covenants and agrees on behalf of himself or herself to deny any Third Party Requests and defend against any legal process which seeks the release of any confidential information that would be released in contravention of the terms of the Non-Disclosure Agreement, and (vi) is not in breach of any Non-Disclosure Agreement entered into with the Office of the Interconnection.

i The Authorized Commission employing or retaining the Authorized Person has provided the Office of the Interconnection with:
i (a) a final order of FERC prohibiting the release by the Authorized Person or the Authorized Commission of confidential
) information in accordance with the terms of this Agreement and the Non-Disclosure Agreement; and (b) either an order of such Authorized Commission or a certification from counsel to such Authorized Commission, confirming that the Authorized Commission (i) has statutory authority to protect the confidentiality of any confidential information received from public release or disclosure and from release or disclosure to any other entity, (ii) will defend against any disclosure of Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders, (iii) will provide the Office of the Interconnection with prompt notice of any such Third Party Request or legal proceedings and will consult with the Office of the Interconnection and/or any Affected Member in its efforts to deny the Third Party Request or defend against such legal process, (iv) in the event a protective order or other remedy is denied, will direct Authorized Persons authorized by it to furnish only that portion of the confidential information which their legal counsel advises the Office of the Interconnection in writing is legally required to be furnished, (v) will exercise its best efforts to obtain assurance that confidential treatment will be accorded to such confidential information and (vi) has adequate procedures to protect against the release of such confidential information; and (c) confirmation in writing that the Authorized Person is authorized by the Commission to enter into the Non-Disclosure Agreement and to receive confidential information under this Agreement.

i The Authorized Commission employing or retaining the Authorized Person has provided the Office of the Interconnection with
i a State Certification.
i
)

i The Office of the Interconnection and the PJM Market Monitor shall be expressly entitled to rely upon such FERC and
v Authorized Commission orders, the State Certification and/or certifications of counsel in providing confidential information to the
) Authorized Person, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder due to the ineffectiveness of the FERC and/or Commission orders, or the inaccuracy of such certification of counsel.

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	Vice President, Government Policy		
IssuedOn:	April 29, 2004		

The Authorized Person may discuss confidential information with other Authorized Persons who are parties to Non-Disclosure Agreements; provided, however, that the Office of the Interconnection shall have confirmed in advance and in writing that it has previously released the confidential information in question to such Authorized Persons. The Office of the Interconnection shall respond to any written request for confirmation within two (2) business days of its receipt.

The Office of the Interconnection shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on its website, or by written request. Such schedule shall be compiled by the Office of the Interconnection, based on information provided by any Authorized Person and/or Authorized Commission. The Office of the Interconnection shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Office of the Interconnection in the compilation and/or maintenance of the schedule.

The PJM Market Monitor or other designated representative of the Office of the Interconnection may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or their Authorized Commission to determine whether additional Information Requests for information are appropriate. The PJM Market Monitor or other representative of the Office of the Interconnection will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section. In any such discussions, the PJM Market Monitor or other representative of the Office of the Interconnection shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The PJM Market Monitor or other representative of the Office of the Interconnection shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The PJM Market Monitor or representative of the Office of the Interconnection shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the Affected

Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, the identity of the Affected Party must be made to the Authorized Person within two (2) business days of the initial oral disclosure.

(c) As regards Information Requests:

(i) Information Requests to the Office of the Interconnection shall be in writing, which shall include electronic communications, addressed to the PJM Market Monitor or other designated representative of the Office of the Interconnection, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only the Authorized Person shall have access to the confidential information requested. The Office of the Interconnection shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request of the Authorized Person as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

(ii) Subject to the provisions of section (c)(iii), the Office of the Interconnection shall supply confidential information to the Authorized Person in response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) business day without the express consent of the Affected Member. To the extent that the Office of the Interconnection can not reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Person with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Person, the Office of the Interconnection shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Office of the Interconnection shall not reveal any Members confidential information to any other Member.

(iii) Notwithstanding section (c)(ii), above, should the Office of the Interconnection or an Affected Member object to an Information Request or any portion thereof, either of them may, within four (4) business days following the Office of the Interconnections receipt of the Information Request, request, in writing, a conference with the Authorized Commission or the Authorized Commissions authorized designee to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then the Office of the Interconnection, the Affected Member or the Authorized Commission may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a fast track complaint and each party shall bear its own costs in connection with such FERC proceeding. If no FERC proceeding regarding the Information Request is commenced within such three day period, the Office of the Interconnection shall utilize its best efforts to respond to the Information Request promptly.

(d) In the event of any breach of a Non-Disclosure Agreement:

(i) The Authorized Person and/or their respective Authorized Commission shall promptly notify the Office of the Interconnection, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to any Non-Disclosure Agreement.

(ii) The Office of the Interconnection shall terminate such Non-Disclosure Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person thereunder shall thereupon terminate; provided, however, that the Office of the Interconnection may restore an individuals status as an Authorized Person after consulting with the Affected Member and to the extent that: (i) the Office of the Interconnection determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damages suffered by the Affected Member; or (iii) similar good cause shown. Any appeal of the Office of the Interconnections actions under this section shall be to FERC.

(iii) The Office of the Interconnection and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Office of the Interconnection.

(iv) No Authorized Person shall have responsibility or liability whatsoever under the Non-Disclosure Agreement or this Agreement for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section (d)(iv) is intended to limit the liability of any person who is not an employee of or a member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.18 Termination and Withdrawal.

18.18.1 Termination.

Upon termination of this Agreement, final settlement for obligations under this Agreement shall include the accounting for the period ending with the last day of the last month for which the Agreement was effective.

IssuedBy: Craig Glazer — Effective: June 29, 2004
Vice President, Government Policy
IssuedOn: July 28, 2004
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER04-776-000, issued June 28, 2004, 107 FERC 61,322.

18.18.2 Withdrawal.

Subject to the requirements of Section 4.1(c) of this Agreement and Section 1.4.6 of the Schedule 1 to this Agreement, any Member may withdraw from this Agreement upon 90 days notice to the Office of the Interconnection.

18.18.3 Winding Up.

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination or expiration of this Agreement shall survive such termination or expiration. The surviving provisions shall include, but shall not be limited to: (i) those provisions necessary to permit the orderly conclusion, or continuation pursuant to another agreement, of transactions entered into prior to the decision to terminate this Agreement, (ii) those provisions necessary to conduct final billing, collection, and accounting with respect to all matters arising hereunder, and (iii) the indemnification provisions as applicable to periods prior to such termination or expiration.

IN WITNESS whereof, the Members have caused this Agreement to be executed by their duly authorized representatives.

RESOLUTION REGARDING ELECTION OF DIRECTORS

1. Subject to the approval of the Federal Energy Regulatory Commission, the provisions of Section 7.1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (the Operating Agreement), to the extent that such section requires that the election of members to the PJM Board of Managers be held at the Annual Meeting of the Members, be, and they hereby are, waived, solely for election to those positions on the PJM Board of Managers that expire in the year 2001; and

2. An election of members of the PJM Board of Managers from the slate approved by the independent consultant retained by the Office of the Interconnection, is, and hereby shall be, authorized by the PJM Members Committee to occur at its meeting held on August 30, 2001; and

3. The Office of the Interconnection is, and hereby shall be, authorized to file such documents and make such pleadings before the Federal Energy Regulatory Commission as the Office of the Interconnection determines to be reasonably necessary seeking such waivers and authorizations as may be required to assure the validity of the aforementioned election of members to the PJM Board of Managers.

SCHEDULE 1

PJM INTERCHANGE ENERGY MARKET

1. MARKET OPERATIONS

1.1 Introduction.

This Schedule sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the PJM Interchange Energy Market within the PJM Region. This Schedule addresses each of the three time-frames pertinent to the daily operation of the PJM Interchange Energy Market: Prescheduling, Scheduling, and Dispatch.

1.2 Cost-based Offers.

Unless and until the FERC shall authorize the use of market-based prices in the PJM Interchange Energy Market, all offers for energy or other services to be sold on the PJM Interchange Energy Market from generating resources located within the PJM Region shall not exceed the variable cost of producing such energy or other service, as determined in accordance with Schedule 2 to this Agreement and applicable regulatory standards, requirements and determinations; provided that, a Market Seller may offer to the PJM Interchange Energy Market the right to call on energy from a resource the output of which has been sold on a bilateral basis, with the rate for such energy if called equal to the curtailment rate specified in the bilateral contract.

1.3 Definitions.

1.3.1 Auction Revenue Rights.

Auction Revenue Rights shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1A Auction Revenue Rights Credits.

Auction Revenue Rights Credits shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B Day-ahead Energy Market.

Day-ahead Energy Market shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C Day-ahead Prices.

Day-ahead Prices shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

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1.3.1D Decrement Bid.

Decrement Bid shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.3.1E Dispatch Rate.

Dispatch Rate shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.2 Equivalent Load.

Equivalent Load shall mean the sum of a Market Participants net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.3 External Market Buyer.

External Market Buyer shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

External Resource shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

Financial Transmission Right or FTR shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

Financial Transmission Right Obligation shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

Financial Transmission Right Option shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

Generating Market Buyer shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyers load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

Generator Forced Outage shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

Generator Planned Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

Increment Bid shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.10 Internal Market Buyer.

Internal Market Buyer shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

Inadvertent Interchange shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM, as determined and allocated each hour by the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals to each Electric Distributor that reports to the Office of the Interconnection its hourly net energy flows from metered tie lines.

1.3.12 Market Operations Center.

Market Operations Center shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.13 Maximum Generation Emergency.

Maximum Generation Emergency shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more Capacity Resources or Available Capacity Resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Capacity Resource, in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

Minimum Generation Emergency shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

NERC Interchange Distribution Calculator shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.15 Network Resource.

Network Resource shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

Network Service User shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

Network Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a West Transmission Owner or an East Transmission Owner.

1.3.18 Normal Maximum Generation.

Normal Maximum Generation shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

Normal Minimum Generation shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

Offer Data shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

Office of the Interconnection Control Center shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.22 Operating Day.

Operating Day shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

Operating Margin shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

Operating Margin Customer shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

PJM Interchange shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

PJM Interchange Export shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

PJM Interchange Import shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

PJM Open Access Same-time Information System shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.29 Point-to-Point Transmission Service.

Point-to-Point Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.30 Ramping Capability.

Ramping Capability shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30A Real-time Prices.

Real-time Prices shall mean the Locational Marginal Prices resulting from the Office of the Interconnections dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

Real-time Energy Market shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.31 Regulation.

Regulation shall mean the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

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1.3.31A Spinning Reserve.

Spinning Reserve shall mean the reserve capability that can be converted fully into energy within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment electrically synchronized to the Transmission System.

1.3.31B Spinning Reserve Event.

Spinning Reserve Event shall mean a request from the Office of the Interconnection to those generation resources able, assigned or self-scheduled to provide Spinning Reserve to increase, within ten minutes, the energy output from those resources by the amount of assigned or self-scheduled Spinning Reserve capability.

1.3.32 Spot Market Backup.

Spot Market Backup shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

Spot Market Energy shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at Locational Marginal Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

State Estimator shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

Station Power shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy used to power synchronous condensers, used for pumping at a pumped storage facility, or used in association with restoration or black start service.

1.3.33C Target Allocation.

Shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

Transmission Congestion Charge shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

Transmission Congestion Credit shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

Transmission Forced Outage shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

Transmission Loading Relief shall mean NERCs procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

Transmission Loading Relief Customer shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.38 Transmission Planned Outage.

Transmission Planned Outage shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.4 Market Buyers.

1.4.1 Qualification.

(a) To become a Market Buyer, an entity shall submit an application to the Office of the Interconnection, in such form as shall be established by the Office of the Interconnection.

(b) An applicant that is a Load Serving Entity or that will purchase on behalf of or for ultimate delivery to a Load Serving Entity shall establish to the satisfaction of the Office of the Interconnection that the end-users that will be served through energy and related services purchased in the PJM Interchange Energy Market, are located electrically within the PJM Region, or will be brought within the PJM Region prior to any purchases from the PJM Interchange Energy Market. Such applicant shall further demonstrate that:

i The Load Serving Entity for the end users is obligated to meet the requirements of the Reliability Assurance Agreement; or) Reliability Assurance Agreement-West, as applicable, and

i The Load Serving Entity for the end users has arrangements in place for Network Transmission Service or Point-To-Point i Transmission Service for all PJM Interchange Energy Market purchases.
)

(c) An applicant that is not a Load Serving Entity or purchasing on behalf of or for ultimate delivery to a Load Serving Entity shall demonstrate that:

i The applicant has obtained or will obtain Network Transmission Service or Point-to-Point Transmission Service for all PJM) Interchange Energy Market purchases; and

i The applicants PJM Interchange Energy Market purchases will ultimately be delivered to a load in another Control Area that is i recognized by NERC and that complies with NERCs standards for operating and planning reliable bulk electric systems.
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(d) An applicant shall not be required to obtain transmission service for purchases from the PJM Interchange Energy Market to cover quantity deviations from its sales in the Day-ahead Energy Market.

(e) All applicants shall demonstrate that:

i The applicant is capable of complying with all applicable metering, data storage and transmission, and other reliability, operation,) planning and accounting standards and requirements for the operation of the PJM Region and the PJM Interchange Energy Market;

i The applicant meets the creditworthiness standards established by the Office of the Interconnection, or has provided a letter of i credit or other form of security acceptable to the Office of the Interconnection; and
)

i The applicant has paid all applicable fees and reimbursed the Office of the Interconnection for all unusual or extraordinary costs
i of processing and evaluating its application to become a Market Buyer, and has agreed in its application to subject any disputes
i arising from its application to the PJM Dispute Resolution Procedures.
)

(f) The applicant shall become a Market Buyer upon a final favorable determination on its application by the Office of the Interconnection as specified below, and execution by the applicant of counterparts of this Agreement.

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1.4.2 Submission of Information.

The applicant shall furnish all information reasonably requested by the Office of the Interconnection in order to determine the applicants qualification to be a Market Buyer. The Office of the Interconnection may waive the submission of information relating to any of the foregoing criteria, to the extent the information in the Office of the Interconnections possession is sufficient to evaluate the application against such criteria.

1.4.3 Fees and Costs.

The Office of the Interconnection shall require all applicants to become a Market Buyer to pay a uniform application fee, initially in the amount of $1,500, to defray the ordinary costs of processing such applications. The application fee shall be revised from time to time as the Office of the Interconnection shall determine to be necessary to recover its ordinary costs of processing applications. Any unusual or extraordinary costs incurred by the Office of the Interconnection in processing an application shall be reimbursed by the applicant.

1.4.4 Office of the Interconnection Determination.

Upon submission of the information specified above, and such other information as shall reasonably be requested by the Office of the Interconnection, the Office of the Interconnection shall undertake an evaluation and investigation to determine whether the applicant meets the criteria specified above. As soon as practicable, but in any event not later than 60 days after submission of the foregoing information, or such later date as may be necessary to satisfy the requirements of the Reliability Assurance Agreement, the Office of the Interconnection shall notify the applicant and the members of the Members Committee of its determination, along with a written summary of the basis for the determination. The Office of the Interconnection shall respond promptly to any reasonable and timely request by a Member for additional information regarding the basis for the Office of the Interconnections determination, and shall take such action as it shall deem appropriate in response to any request for reconsideration or other action submitted to the Office of the Interconnection not later than 30 days from the initial notification to the Members Committee.

1.4.5 Existing Participants.

Any entity that was qualified to participate as a Market Buyer in the PJM Interchange Energy Market under the Operating Agreement of PJM Interconnection L.L.C. in effect immediately prior to the Effective Date shall continue to be qualified to participate as a Market Buyer in the PJM Interchange Energy Market under this Agreement.

1.4.6 Withdrawal.

(a) An Internal Market Buyer that is a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal not earlier than the effective date of (i) its withdrawal from the Reliability Assurance Agreement or Reliability Assurance Agreement-West, or (ii) the assumption of its obligations under the Reliability Assurance Agreement or Reliability Assurance Agreement-West by an agent that is a Market Buyer.

(b) An External Market Buyer or an Internal Market Buyer that is not a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice.

(c) Withdrawal from this Agreement shall not relieve a Market Buyer of any obligation to pay for electric energy or related services purchased from the PJM Interchange Energy Market prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions or events occurring prior to such withdrawal; and provided, further, that withdrawal from this Agreement shall not relieve any Market Buyer of any obligations it may have under, or constitute withdrawal from, any other Related PJM Agreement.

(d) A Market Buyer that has withdrawn from this Agreement may reapply to become a Market Buyer in accordance with the provisions of this Section 1.4, provided it is not in default of any obligation incurred under this Agreement.

1.5 Market Sellers.

1.5.1 Qualification.

A Member that demonstrates to the Office of the Interconnection that the Member meets the standards for the issuance of an order mandating the provision of transmission service under section 211 of the Federal Power Act, as amended by the Energy Policy Act of 1992, may become a Market Seller upon execution of this Agreement and submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule. All Members that are Market Buyers shall become Market Sellers upon submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule.

1.5.2 Withdrawal.

(a) A Market Seller may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice; provided, however, that withdrawal shall not relieve a Market Seller of any obligation to deliver electric energy or related services to the PJM Interchange Energy Market pursuant to an offer made prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions, or events occurring prior to such withdrawal; and provided, further, that withdrawal shall not relieve any entity that is a Market Seller and is also a Market Buyer of any obligations it may have as a Market Buyer under, or constitute withdrawal as a Market Buyer from, this Agreement or any other Related PJM Agreement.

(b) A Market Seller that has withdrawn from this Agreement may reapply to become a Market Seller at any time, provided it is not in default with respect to any obligation incurred under this Agreement.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

The Office of the Interconnection shall operate the PJM Interchange Energy Market in accordance with this Agreement.

1.6.2 Scope of Services.

The Office of the Interconnection shall, on behalf of the Market Participants, perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including but not limited to the following:

i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, rendering bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants, maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the Office of the Interconnection Agreement, and the Schedules to this Agreement;

ii) Review and evaluate the qualification of entities to be Market Buyers or Market Sellers under applicable provisions of this Agreement;

iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, the West Transmission Owners Agreement and the East Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;

iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;

v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;

Enter into (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

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vi) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Reliability Council principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;

viii) Protect confidential information as specified in this Agreement; and

ix) Send a representative to meetings of the Members Committee or other Committees, subcommittees, or working groups specified in this Agreement or formed by the Members Committee when requested to do so by the chair or other head of such committee or other group.

1.6.3 Records and Reports.

The Office of the Interconnection shall prepare and maintain such records and prepare such reports, including, but not limited to quarterly budget reports, as are required to document the performance of its obligations to the Market Participants hereunder in a form adopted by the Office of the Interconnection upon consideration of the advice and recommendations of the Members Committee. The Office of the Interconnection shall also produce special reports reasonably requested by the Members Committee and consistent with FERCs standards of conduct; provided, however, the Market Participants shall reimburse the Office of the Interconnection for the costs of producing any such report. Notwithstanding the foregoing, the Office of the Interconnection shall not be required to disclose confidential or commercially sensitive information in any such report.

1.6.4 PJM Manuals.

The Office of the Interconnection shall prepare, maintain and update the PJM Manuals consistent with this Agreement. The PJM Manuals shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the LLC or any Member, and the public.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

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1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participants PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer to conform to the requirements for purchasing from the PJM Interchange Energy Market.

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1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation is dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers, as well as the requirements of the PJM Region for ancillary services provided by such generation, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38). Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges, which shall be determined by differences in Locational Marginal Prices in an hour caused by transmission constraints, shall be calculated and collected, and the revenues therefrom shall be disbursed, by the Office of the Interconnection in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyers Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Capacity Resources available for dispatch by the Office of the Interconnection. Bilateral arrangements that contemplate the physical transfer of energy to or from a Market Participant shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyers generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), net output of a generation facility during any month means the facilitys gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facilitys or a Market Sellers monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For

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each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the locational marginal price (LMP) at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in clause (1) of paragraph (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in clause (2) of paragraph (d)(i) above (hereafter referred to as remote self-supply of Station Power), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facilitys negative net output from Market Sellers generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for non-firm point-to-point transmission service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

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1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This paragraph shall be implemented consistent with North American Electic Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

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1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy

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Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated seasonally for various peak load levels and eight weekly periods and is published in the PJM Manuals. Reserve levels are probabilistically determined based on the seasons historical load forecasting error and expected generation mix (including typical Planned and Forced/Unplanned Outages). Operating Reserve objectives will be determined for the ECAR Control Zone(s) and MAIN Control Zone(s), in accordance with ECAR and MAIN requirements, respectively. Generating Units with quick start capability, as specified in the PJM Manuals, that are dispatched to maintain reliability by providing load following capability shall receive energy payments at the levels specified below. The energy payments specified below shall be considered the offered price for Spot Market Energy for purposes of Section 3.2.3(b) of this Schedule. The price offered or paid for the energy of units so dispatched shall not be considered in determining Locational Marginal Prices.

(c) Payments for energy produced by a quick start generating unit dispatched as specified above shall be at the higher of the applicable Locational Marginal Price or one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result

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in a price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) The incremental operating cost of the generation resource as determined in accordance with Schedule 2 of this Agreement and the PJM Manuals, plus 10% of such costs; or

(iii) An amount determined by agreement between the Office of the Interconnection and the Market Seller.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generators located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned.

(d) A unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that unit, in that the amount of Regulation shall be added to the units Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.

(e) Qualified Regulation must satisfy the verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generators megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Spinning Reserve.

a) Spinning Reserve shall be supplied from generators located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Spinning Reserve shall comply with applicable standards and requirements for Spinning Reserve capability and dispatch specified in the PJM Manuals.

b) The Office of the Interconnection shall obtain and maintain for each Spinning Reserve Zone an amount of Spinning Reserve equal to the Spinning Reserve objective for such Spinning Reserve Zone, as specified in the PJM Manuals.

c) The Spinning Reserve capability of a unit shall be the increase in energy output achievable by the unit within a continuous 10-minute period.

d) A unit capable of automatic energy dispatch that also is providing Spinning Reserve shall have its energy dispatch range reduced by the amount of the Spinning Reserve provided. The amount of Spinning Reserve provided by a unit shall serve to redefine the Normal Maximum Generation energy limit of that unit in that the amount of Spinning Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participants relevant load or facilities sufficient to meet the requirements of the Market Participants transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from resources within the PJM Region shall: report to the Office of the Interconnection sources of energy available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection units that are self-scheduled; report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnections directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment is operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Sellers Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process

1.8.1 PJM Dispute Resolution Agreement.

Subject to the condition specified below, any Member adversely affected by a decision of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market, including the qualification of an entity to participate in that market as a buyer or seller, may seek such relief as may be appropriate under the PJM Dispute Resolution Procedures on the grounds that such decision does not have an adequate basis in fact or does not conform to the requirements of this Agreement.

1.8.2 Market or Control Area Hourly Operational Disputes.

(a) Market Participants shall comply with all determinations of the Office of the Interconnection on the selection, scheduling or dispatch of resources in the PJM Interchange Energy Market, or to meet the operational requirements of the PJM Region. Complaints arising from or relating to such determinations shall be brought to the attention of the Office of the Interconnection not later than the end of the fifth business day after the end of the Operating Day to which the selection or scheduling relates, or in which the scheduling or dispatch took place, and shall include, if practicable, a proposed resolution of the complaint. Upon receiving notification of the dispute, the Office of the Interconnection and the Market Participant raising the dispute shall exert their best efforts to obtain and retain all data and other information relating to the matter in dispute, and to notify other Market Participants that are likely to be affected by the proposed resolution. Subject to confidentiality or other non-disclosure requirements, representatives of the Office of the Interconnection, the Market Participant raising the dispute, and other interested Market Participants, shall meet within three business days of the foregoing notification, or at such other or further times as the Office of the Interconnection and the Market Participants may agree, to review the relevant facts, and to seek agreement on a resolution of the dispute.

(b) If the Office of the Interconnection determines that the matter in dispute discloses a defect in operating policies, practices or procedures subject to the discretion of the Office of the Interconnection, the Office of the Interconnection shall implement such changes as it deems appropriate and shall so notify the Members Committee. Alternatively, the Office of the Interconnection may notify the Members Committee of a proposed change and solicit the comments or other input of the Members.

(c) If either the Office of the Interconnection, the Market Participant raising the dispute, or another affected Market Participant believes that the matter in dispute has not been

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adequately resolved, or discloses a need for changes in standards or policies established in or pursuant to the Operating Agreement, any of the foregoing parties may make a written request for review of the matter by the Members Committee, and shall include with the request the forwarding partys recommendation and such data or information (subject to confidentiality or other non-disclosure requirements) as would enable the Members Committee to assess the matter and the recommendation. The Members Committee shall take such action on the recommendation as it shall deem appropriate.

(d) Subject to the right of a Market Participant to obtain correction of accounting or billing errors, the LLC or a Market Participant shall not be entitled to actual, compensatory, consequential or punitive damages, opportunity costs, or other form of reimbursement from the LLC or any other Market Participant for any loss, liability or claim, including any claim for lost profits, incurred as a result of a mistake, error or other fault by the Office of the Interconnection in the selection, scheduling or dispatch of resources.

1.9 Prescheduling.

The following procedures and principles shall govern the prescheduling activities necessary to plan for the reliable operation of the PJM Region and for the efficient operation of the PJM Interchange Energy Market.

1.9.1 Outage Scheduling.

The Office of the Interconnection shall be responsible for coordinating and approving requests for outages of generation and transmission facilities as necessary for the reliable operation of the PJM Region, in accordance with the PJM Manuals. The Office of the Interconnection shall maintain records of outages and outage requests of these facilities.

1.9.2 Planned Outages.

(a) A Generator Planned Outage shall be included in Generator Planned Outage schedules established prior to the scheduled start date for the outage, in accordance with standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall conduct Generator Planned Outage scheduling for Capacity Resources in accordance with the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the PJM Manuals and in consultation with the Members owning or controlling the output of Capacity Resources. A Market Participant shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from all or part of a generation resource undergoing an approved Generator Planned Outage. If the Office of the Interconnection determines that approval of a Generator Planned Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval or withdraw a prior approval. Approval for a Generator Planned Outage of a Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. If the Office of the Interconnection withholds or withdraws approval, it shall coordinate with the Market Participant owning or controlling the resource to reschedule the

Generator Planned Outage of the Capacity Resource at the earliest practical time. The Office of the Interconnection shall if possible propose alternative schedules with the intent of minimizing the economic impact on the Market Participant of a Generator Planned Outage.

(c) The Office of the Interconnection shall conduct Transmission Planned Outage scheduling in accordance with procedures specified in, as applicable, the East Transmission Owners Agreement or West Transmission Owners Agreement and the PJM Manuals, and in accordance with the following procedures:

(i) Transmission Owners shall submit Transmission Planned Outage schedules one year in advance for all outages that are expected to exceed five working days duration or that are anticipated to result in significant system impacts, with regular (at least monthly) updates as new information becomes available.

(ii) Transmission Owners shall submit notice of all Transmission Planned Outages to the Office of the Interconnection by the first day of the month preceding the month the outage will commence, with updates as new information becomes available.

(iii) If notice of a Transmission Planned Outage is not provided by the first day of the month preceding the month the outage will commence, and if such outage is determined by the Office of the Interconnection to have the potential to cause transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid the congestion. The Office of the Interconnection shall perform this analysis and notify the Transmission Owner in a timely manner if it will require rescheduling of the outage.

(iv) The Office of the Interconnection shall post notice of Transmission Planned Outages on OASIS upon receipt of such notice from the Transmission Owner; provided, however, that the Office of the Interconnection shall not post on OASIS notice of any component of a Transmission Planned Outage to the extent such component shall directly reveal a generator outage. In such cases, the Transmission Owner, in addition to providing notice to the Office of Interconnection as required above, concurrently shall inform the affected Generation Owner of such outage, limiting such communication to that necessary to describe the outage and to coordinate with the Generation Owner on matters of safety to persons, facilities, and equipment. The Transmission Owner shall not notify any other Market Participant of such outage and shall arrange any other necessary coordination through the Office of the Interconnection.

In addition, if the Office of the Interconnection determines that transmission maintenance schedules proposed by one or more Members would significantly affect the efficient and reliable operation of the PJM Region, the Office of the Interconnection may

establish alternative schedules, but such alternative shall minimize the economic impact on the Member or Members whose maintenance schedules the Office of the Interconnection proposes to modify.

(d) The Office of the Interconnection shall coordinate resolution of outage or other planning conflicts that may give rise to unreliable system conditions. The Members shall comply with all maintenance schedules established by the Office of the Interconnection.

1.9.3 Generator Maintenance Outages.

A Market Participant may request approval for a Generator Maintenance Outage of any Capacity Resource from the Office of the Interconnection in accordance with the timetable and other procedures specified in the PJM Manuals. The Office of the Interconnection shall approve requests for Generator Maintenance Outages for a Capacity Resource unless the outage would threaten the adequacy of reserves in, or the reliability of, the PJM Region. A Market Participant shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from a generation resource undergoing an approved full or partial Generator Maintenance Outage.

1.9.4 Forced Outages.

(a) Each Market Seller that owns or controls a pool-scheduled resource, or Capacity Resource whether or not pool-scheduled, shall: (i) advise the Office of the Interconnection of a Generator Forced Outage suffered or anticipated to be suffered by any such resource as promptly as possible; (ii) provide the Office of the Interconnection with the expected date and time that the resource will be made available; and (iii) make a record of the events and circumstances giving rise to the Generator Forced Outage. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or satisfy delivery obligations, from a generation resource undergoing a Generator Forced Outage. A Capacity Resource that does not deliver all or part of its scheduled energy shall be deemed to have experienced a Generator Forced Outage with respect to such undelivered energy, in accordance with standards and procedures for full and partial Generator Forced Outages specified in the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the PJM Manuals.

(b) The Office of the Interconnection shall receive notification of Forced Transmission Outages, and information on the return to service, of Transmission Facilities in the PJM Region in accordance with standards and procedures specified in, as applicable, the East Transmission Owners Agreement or West Transmission Owners Agreement and the PJM Manuals.

1.9.5 Market Participant Responsibilities.

Each Market Participant making a bilateral sale covering a period greater than the following Operating Day from a generating resource located within the PJM Region for delivery outside the PJM Region shall furnish to the Office of the Interconnection, in the form and manner specified in the

PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered.

1.9.6 Internal Market Buyer Responsibilities.

Each Internal Market Buyer making a bilateral purchase covering a period greater than the following Operating Day shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered. Each Internal Market Buyer shall provide the Office of the Interconnection with details of any load management agreements with customers that allow the Office of the Interconnection to reduce load under specified circumstances.

1.9.7 Market Seller Responsibilities.

(a) Not less than 30 days before a Market Sellers initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources.

(b) Market Sellers authorized to request market-based start-up fees may choose to submit either market-based or cost-based start-up fees.

(i) If a Market Seller chooses to submit market-based start-up and no-load fees, such Market Seller, in its Offer Data, shall submit a specification of such fees to the Office of the Interconnection for each generating unit as to which the Market Seller intends to request such fees. Any such specification shall be submitted on or before March 31 for the period April 1 through September 30, and on or before September 30 for the period October 1 through March 31, and shall remain in effect without change throughout each such period for which a specification was submitted. The Office of the Interconnection shall reject any request for start-up and no-load fees in a Market Sellers Offer Data that does not conform to the Market Sellers specification on file with the Office of the Interconnection.

(ii) If a Market Seller chooses to submit cost-based start-up fees, the start-up fee may be changed daily.

1.9.8 Transmission Owner Responsibilities.

All Transmission Owners shall regularly update and verify facility ratings, subject to review and approval by PJM, in accordance with the following procedures and the procedures in the PJM Manuals:

(a) Each Transmission Owner shall verify to the Operations Planning Department (or successor Department) of the Office of the Interconnection all of its transmission facility ratings two months prior to the beginning of the summer season (i.e., on April 1) and two months prior to the beginning of the winter season (i.e., on October 1) each calendar year, and

shall provide detailed data justifying such transmission facility ratings when directed by the Office of the Interconnection.

(b) In addition to the seasonal verification of all ratings, each Transmission Owner shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection updates to its transmission facility ratings as soon as such Transmission Owner is aware of any changes. Such Transmission Owner shall provide the Office of the Interconnection with detailed data justifying all such transmission facility ratings changes.

(c) All Transmission Owners shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection formal documentation of any procedure for changing facility ratings under specific conditions, including: the detailed conditions under which such procedures will apply, detailed explanations of such procedures, and detailed calculations justifying such pre-established changes to facility ratings. Such procedures must be updated twice each year consistent with the provisions of this Section.

1.9.9 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall perform seasonal operating studies to assess the forecasted adequacy of generating reserves and of the transmission system, in accordance with the procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall maintain and update tables setting forth Operating Reserve and other reserve objectives as specified in the PJM Manuals and as consistent with the Reliability Assurance Agreement and Reliability Assurance Agreement-West.

(c) The Office of the Interconnection shall receive and process requests for firm and non-firm transmission service in accordance with procedures specified in the PJM Tariff.

(d) The Office of the Interconnection shall maintain such data and information relating to generation and transmission facilities in the PJM Region as may be necessary or appropriate to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM Region.

(e) The Office of the Interconnection shall maintain an historical database of all transmission facility ratings, and shall review, and may modify or reject, any submitted change or any submitted procedure for pre-established transmission facility rating changes. Any dispute between a Transmission Owner and the Office of the Interconnection concerning transmission facility ratings shall be resolved in accordance with the dispute resolution procedures in schedule 5 to the Operating Agreement; provided, however, that the rating level determined by the Office of the Interconnection shall govern and be effective during the pendency of any such dispute.

(f) The Office of the Interconnection shall coordinate with other interconnected Control Area as necessary to manage, alleviate or end an Emergency.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy market.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable transmission customers to reserve transmission service with Transmission Congestion Charges based on locational differences in Day-ahead Prices. Market Participants whose purchases and sales, and transmission customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or transmission customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnections forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyers intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnections Offer Data specification, as applicable. Market Sellers owning or controlling the output of a Capacity Resource that has not been rendered unavailable by a Generation Planned Outage, a Generator Maintenance Outage, or a Generation Forced Outage shall submit offers for the available capacity of such Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer claiming the resource as a Capacity Resource. The submission of offers for resource increments that are not Capacity Resources shall be optional, but any such offers must contain the information specified in the Office of the Interconnections Offer Data specification, as applicable. Energy offered from generation resources that are not Capacity Resources shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the generation resource and energy for each hour in the offer period;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii Shall not exceed an energy offer price of $1,000/megawatt-hour.
)

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the MW of Regulation being offered, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resources opportunity costs. The price of the offer shall not exceed $100 per MWh in the case of regulation offered for the MAAC Control Zone. Regulation offered for any Regulation Zone comprised of the ECAR Control Zone(s), or MAIN Control Zone(s) shall be cost-based (including opportunity costs) plus seven dollars and fifty cents until such time as market-based pricing is approved for regulation in such Regulation Zone. Qualified Regulation capability must satisfy the verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Capacity Resource shall submit a forecast of the availability of each such Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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Note: This sheet includes language accepted by the Commission which will be included in a clean up filing.

(g) Each offer by a Market Seller of a Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) All Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

(j) A Market Seller that wishes to make a resource available to sell Spinning Reserve shall submit an offer for Spinning Reserve that shall specify the megawatt of Spinning Reserve being offered, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the resource to provide the Spinning Reserve and the resources unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Spinning Reserve plus seven dollars and fifty cents.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

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(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resources start-up cost, if the Office of the

Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Capacity Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. A Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Capacity Resource that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. A Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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(c) A Capacity Resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Sellers Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data. If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the load bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyers load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged or credited at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing load bus or buses.

(b) An External Market Buyers hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

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(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Members energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entitys energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM

Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnections forecasts of PJM Interchange Energy Market and PJM Control Area, and PJM West Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers and Market Buyers of their scheduled injections and withdrawals respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors. The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.

(d) Market Buyers shall pay and Market Sellers shall be paid for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation offer data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the

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obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Sellers offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the

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output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Capacity Resources may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each resources regulation offer and the estimated opportunity cost of the resource providing regulation and in accordance with the Office of the Interconnections obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Spinning Reserve

a) A Market Buyer may satisfy its Spinning Reserve Obligation from its own resources capable of providing Spinning Reserve, by contractual arrangements with other Market Participants able to provide Spinning Reserve, or by purchases from the PJM Spinning Reserve Market at the rates set forth in Section 3.2.3A.

b) The Office of the Interconnection shall obtain Spinning Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet the Spinning Reserve requirements of each Spinning Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Spinning Reserve shall be selected to provide Spinning Reserve on the basis of each resources Spinning Reserve offer and the estimated unit specific opportunity cost of the resource providing Spinning Reserve, and in accordance with the Office of the Interconnections obligation to minimize the total cost of energy, Operating Reserves, Spinning Reserve and other ancillary services. Estimated unit specific opportunity costs shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Spinning Reserve as submitted as part of the resources Spinning Reserve offer times (B) the Locational Marginal Price at the generation bus of the resource, and (ii) the product of (A) the deviation of the resources output necessary to follow the Office of the Interconnections signals and instructions from the resources expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Spinning Reserve set point for the resource) in the PJM Interchange Energy Market.

c) The Office of the Interconnection shall dispatch resources for Spinning Reserve by sending Spinning Reserve instructions to resources from which Spinning Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Spinning Reserve dispatch instructions transmitted by the Office of the

Interconnection and, in the event of a conflict, Spinning Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

1.12 Dynamic Scheduling.

(a) An entity that owns or controls a generating resource in the PJM Region may electrically remove all or part of the generating resources output from the PJM Region through dynamic scheduling of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection.

(b) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communications from the generator to the Office of the Interconnection and other participating control areas and complying with any other procedures established by the Office of the Interconnection regarding dynamic scheduling as set forth in the PJM Manuals.

(c) An entity requesting dynamic scheduling shall be responsible for reserving amounts of firm transmission service necessary to deliver the range of the dynamic transfer and any required ancillary services.

2. CALCULATION OF LOCATIONAL MARGINAL PRICES

2.1 Introduction.

The Office of the Interconnection shall calculate the price of energy at the load busses and generation busses in the PJM Region and at the interface busses between adjacent Control Areas and the PJM Region on the basis of Locational Marginal Prices. Locational Marginal Prices determined in accordance with this Section shall be calculated on a day-ahead basis for each hour of the Day-ahead Energy Market, and every five minutes during the Operating Day for the Real-time Energy Market.

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas, will be obtained from the Office of the Interconnections dispatchers.

(b) Using the prices at which energy is offered by Market Sellers to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every offer of energy by a Market Seller from a resource that is following economic dispatch instructions of the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator, which is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnections dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine which resources are following its economic dispatch instructions. A resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-time Prices if:

ithe applicable price bid by a Market Seller for energy from the resource is less than or equal to the Dispatch Rate for the area of
)the PJM Region in which the resource is located; or

ithe resource is specifically requested to operate by the Office of the Interconnections dispatcher.
i
)

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the bid price associated with an energy offer by comparing the actual megawatt output of the resource with the Market Sellers offer price curve. Because of practical generator response limitations, a resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region represented in the State Estimator and each interface bus between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying an incremental linear optimization method to minimize energy costs, given actual system conditions, a set of energy offers, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of: (1) the price at which the Market Seller has offered to supply an additional increment of energy from the resource, and (2) the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of the resource, based on the effect of increased generation from that resource on transmission line loadings. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.

(b) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnections Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

2.6 Calculation of Day-ahead Prices.

For the Day-ahead Energy Market, day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications, offers for generation, dispatchable load, Increment Bids, Decrement Bids, and bilateral transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of: (1) the price at which the Market Seller has offered to supply an additional increment of energy from the resource, and (2) the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of the resource, based on the effect of increased generation from that resource on transmission line loadings. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.

2.7 Performance Evaluation.

The Office of the Interconnection shall undertake an evaluation of the foregoing procedures for the determination of Locational Marginal Prices, as well as the procedures for determining and allocating Financial Transmission Rights and associated Transmission Congestion Charges and Credits, not less often than every two years, in accordance with the PJM Manuals. To the extent practical, the Office of the Interconnection shall retain all data needed to perform comparisons and other analyses of locational marginal pricing. The Office of the Interconnection shall report the results of its evaluation to the Market Participants, along with its recommendations, if any, for changes in the procedures.

3. ACCOUNTING AND BILLING

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

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3.2 Market Buyers.

3.2.1 Spot Market Energy.

(a) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Prices applicable to each relevant load bus.

(b) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Prices applicable to each relevant generation bus.

(c) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the load payment at each Market Buyers load bus to be charged at Real-time Prices determined by the product of the hourly Real-time Price at the relevant bus times the Market Buyers megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be credited for the difference at the Real-time Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer as determined by the State Estimator, plus an allocated share of transmission losses, plus any megawatts of that Market Buyers bilateral sales to purchasers outside of the PJM Region attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyers load buses, of the charges at Day-ahead Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Prices determined as specified herein, net of any credits specified herein for each of the Market Buyers load buses.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the generation revenue at each Generating Market Buyers generation bus to be paid at Real-time Prices, determined by the product of the hourly Real-time Price at the relevant bus times the Generating Market Buyers megawatts of generation at such generation bus in the hour, as determined by the State Estimator, in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer as determined by the State Estimator, plus any megawatts of bilateral purchases of that Generating Market Buyer from sellers outside of the PJM Region attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyers generation buses, of the revenues at Day-ahead Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Prices determined as specified herein, net of any debits specified herein for each of the Market Buyers generation buses.

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(e) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate a net bill for each Market Buyer, determined as the difference between its total load charges and its total generation revenue. The portions of the net bill attributable to net hourly PJM Interchange and to Transmission Congestion Charges in the Day-ahead Energy Market and the Real-time Energy Market shall be determined as set forth in this Section and in Section 5.1.3.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entitys Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyers transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For Electric Distributors that report hourly net energy flows from metered tie lines, this calculation also shall include 500 kV transmission losses and Inadvertent Interchange allocated to the Electric Distributor and shall exclude the energy delivered to load of other Network Customers and Transmission Customers. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(g) The Office of the Interconnection shall calculate Locational Marginal Prices in the form of Day-ahead Prices and Real-time Prices for each load and generation bus in the PJM Region, in accordance with Section 2 of this Schedule.

(h) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(f) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(f) above. The Office of the Interconnection shall calculate an hourly weighted average Real-time Price for each such Market Buyer, based on the hourly average of the Market Buyers Real-time Prices at each bus weighted by the Market Buyers load deviations at the bus. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly weighted-average Real-time Price for that Market Buyer.

(i) A Generating Market Buyer shall be credited as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(f) above. The Office of the Interconnection shall calculate an hourly weighted average Real-time Price for each such Market Seller, based on the hourly average of the Market Sellers Real-time Prices at each bus weighted by the Market Buyers generation deviations at each bus. The total credit shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly weighted average Real-time Price for that Market Seller.

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3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its *pro rata* share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyers total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour (Regulation Obligation). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with paragraph (c) of this Section, plus the amounts, if any, described in paragraph (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day and the market-clearing price each hour shall be equal to the highest sum of a resources Regulation offer plus its estimated unit-specific opportunity costs from among the resources selected to provide Regulation. A resources Regulation offer for any of the Regulation Zone(s) in the PJM West Region shall not exceed the cost of providing Regulation from such resource, plus seven dollars and fifty cents, unless and until market-based pricing is authorized for Regulation in such Regulation Zone.

(d) In determining the Regulation market-clearing price in each Regulation Zone, the estimated unit-specific opportunity costs of a resource offering to sell Regulation each hour shall be equal to the product of (i) the deviation of the set point of the resource that is expected to be required in order to provide Regulation from the resources expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnections Regulation signals and instructions, the unit-specific opportunity cost of a resource shall be determined for each hour that the Office of the Interconnection requires a resource to provide Regulation and shall be equal to the product of (i) the deviation of the resources output necessary to follow the Office of the Interconnections Regulation signals from the resources expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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3.2.3 Operating Reserves.

(a) A Market Sellers pool-scheduled resources capable of providing operating reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and Spot Market Energy, determined on the basis of the resources scheduled output, shall be compared to the total value of that resources Spot Market Energy as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Spinning Reserve: the total offered price for start-up and no-load fees and Spot Market Energy, determined on the basis of the lesser of the resources (i) hourly output as determined by the State Estimator, or (ii) requested output as determined by the PJM dispatch. The total offered price shall be compared to the total value of that resources energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day. Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) and less any amounts credited for Regulation in excess of the Regulation offer plus the resources opportunity cost and less any amounts credited for Spinning Reserve in excess of the Spinning Reserve offer plus the resources opportunity cost, shall be credited to the Market Seller.

(f) A Market Sellers steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the units bus is higher than the units offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJMs unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP UB)}, where:

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LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the units bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Sellers combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the units bus is higher than the units offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP UDALMP) x DAG}, or (ii) {(URTLMP UB) x DAG} where:

URTLMP equals the real time LMP at the units bus;

UDALMP equals the day-ahead LMP at the units bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP UB shall not be negative.

(f-2) A Market Sellers hydroelectric resource that is pool scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller can demonstrate to the satisfaction of the Office of the Interconnection and the Market Monitoring Unit that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a units output due to a transmission constraint or other reliability issue, then the Office of the Interconnection will negotiate with the individual Market Seller such appropriate compensation, subject to approval of such compensation by the Market Monitoring Unit.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the Real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Spinning Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Spinning Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Spinning Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Spinning Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Spinning Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not

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including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (Maximum Generation Emergency Alert); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in paragraphs (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in clause (i), (ii), or (iii) of this paragraph (l) (collectively referred to as MaxGen Conditions). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case paragraphs (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this paragraph (m), the Effective Offer Price shall be the amount that, absent paragraphs (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatthours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for Spot Market Energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for Spot Market Energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not

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receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this paragraph (n), the Effective Offer Price shall be the amount that, absent paragraphs (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for Spot Market Energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this paragraph, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent paragraphs (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then paragraph (m) does not apply.

3.2.3A Spinning Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Spinning Reserve equal to its *pro rata* share of Spinning Reserve requirements for the hour for each Spinning Reserve Zone of the PJM Region, based on the Market Buyers total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Spinning Reserve Zone, for the hour (Spinning Reserve Obligation), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Spinning Reserve Obligation shall be charged for the Spinning Reserve dispatched by the Office of the Interconnection to meet such obligation at the Spinning Reserve Market Clearing Price determined in accordance with paragraph (d) of this section, plus the amounts if any, described in paragraphs (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Spinning Reserve at the direction of the Office of the Interconnection, in excess of its hourly Spinning Reserve Obligation, shall be credited as follows:

i) Credits for Spinning Reserve provided by units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output in response to a Spinning

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Reserve Event (Tier 1 Spinning Reserve) shall be at the Spinning Energy Premium Price.

ii) Credits for Spinning Reserve provided by units that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions (Tier 2 Spinning Reserve) shall be the higher of (i) the Spinning Reserve Market Clearing Price or (ii) the sum of (A) the Spinning Reserve offer, and (B) the unit specific opportunity cost of the resource supplying the increment of Spinning Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

c) The Spinning Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Spinning Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

d) The Spinning Reserve Market Clearing Price shall be determined for each Spinning Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the resources selected to provide Spinning Reserve for such Spinning Reserve Zone, the highest sum of (i) a resources Spinning Reserve offer and (ii) the unit specific opportunity cost of the resource.

e) In determining the Spinning Reserve Market Clearing Price, the estimated unit-specific opportunity cost shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the resource times (B) the megawatts of energy used to provide Spinning Reserve submitted as part of the Spinning Reserve offer and (ii) the product of (A) the deviation of the set point of the resource that is expected to be required in order to provide Spinning Reserve from the resources expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Spinning Reserve set point for the resource) in the PJM Interchange Energy Market.

f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Spinning Reserve and that actively follows the Office of the Interconnections signals and instructions, the unit-specific opportunity cost of a resource shall be determined for each hour that the Office of the Interconnection requires a resource to provide Tier 2 Spinning Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Spinning Reserve as submitted as part of the resources Spinning Reserve offer times (B) the Locational Marginal Price at the generation bus of the resource, and (ii) the product of (A) the deviation of the resources output necessary to follow the Office of the Interconnections signals and instructions from the resources expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the resource and the offer price for energy from the resource (at the megawatt level of the Spinning Reserve set point for the resource) in the PJM Interchange Energy Market.

g) Charges for Tier 1 Spinning Reserve will be allocated in proportion to the amount of Tier 1 Spinning Reserve applied to each Spinning Reserve Obligation. In the event Tier 1 Spinning Reserve is provided by a Market Seller in excess of that Market Sellers Spinning Reserve Obligation, the remainder of the Tier 1 Spinning Reserve that is not utilized to fulfill the Sellers obligation will be allocated proportionately among all other Spinning Reserve Obligations.

h) Any amounts credited for Tier 2 Spinning Reserve in an hour in excess of the Spinning Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Spinning Reserve Obligation in proportion to its purchases of Spinning Reserve in megawatt-hours during that hour.

i) In the event the Office of the Interconnection needs to assign more Tier 2 Spinning Reserve during an hour than was estimated as needed at the time the Spinning Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Spinning Reserve, the costs of the excess Tier 2 Spinning Reserve shall be allocated and charged to those providers of Tier 1 Spinning Reserve whose available Tier 1 Spinning Reserve was reduced from the needed amount estimated during the Spinning Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Spinning Reserve availability.

j) In the event a resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Spinning Reserve fails to provide the assigned or self-scheduled amount of Spinning Reserve in response to an actual Spinning Reserve Event, the owner of the resource shall incur an additional Spinning Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Spinning Event at least three business days following the Spinning Reserve Event. The overall Spinning Reserve requirement for each Spinning Reserve Zone of the PJM Region on which the Spinning Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Sellers resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

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(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), and where the hourly integrated, real time LMP at the units bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJMs unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the units bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the units bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP UDALMP) x DAG, or (ii) {(URTLMP UB) x DAG where:

URTLMP equals the real time LMP at the units bus;

UDALMP equals the day-ahead LMP at the units bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Sellers unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the units bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), and where the hourly integrated, real time LMP at the units bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJMs unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the units bus; and

where UB - URTLMP shall not be negative.

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(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to paragraph 1.10.3 (c)), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller can demonstrate to the satisfaction of the Office of the Interconnection and the Market Monitoring Unit that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnections dispatch instructions to reduce or suspend a units output for the purpose of maintaining reactive reliability, then the Office of the Interconnection will provide such alternate lost opportunity cost compensation to the Market Seller as can be agreed upon by the Market Seller, the Office of the Interconnection and the Market Monitoring Unit.

(i) The amount of spinning reserve provided by units maintaining reactive reliability shall be counted as Spinning Reserve satisfying the overall PJM Spinning Reserve requirements. Operators of these units shall be notified of such provision, and to the extent a units operator indicates that the unit is capable of providing Spinning Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Spinning Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Spinning Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Spinning Reserve Market Clearing Price for each hour a unit provided synchronous condensing multiplied by the amount of spinning reserve provided by the synchronous condenser or (ii) the sum of (A) the units hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the units bus, (C) the units startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the resource supplying the increment of Spinning Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Spinning Reserve, the Market Seller shall be credited only for the units cost to condense, as described in (ii) above. The total Spinning Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Spinning Reserve requirements. The Spinning Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Spinning Reserve are allocated to such Load Serving Entity pursuant to paragraph (l) below.

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(j) A Market Sellers pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the units offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the units inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element (contingency flow) exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility (post-contingency operation). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of spinning reserve provided by synchronous condensers associated with post-contingency operation shall be counted as spinning reserve satisfying the PJM Spinning Reserve requirements. Operators of these units shall be notified of such provision, and to the extent a units operator indicates that the unit is capable of providing Spinning Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Spinning Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Spinning Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Spinning Reserve Market Clearing Price for each hour a resource provided synchronous condensing multiplied by the amount of spinning reserve provided by the synchronous condenser or (ii) the sum of (A) the resources hourly cost to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the resource, (C) the resources start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the resource supplying the increment of Spinning Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Spinning Reserve, the Market Seller shall be credited only for the units cost to condense, as described in (ii) above. The total Spinning Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Spinning Reserve requirements. The Spinning Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Spinning Reserve are allocated to such Load Serving Entity pursuant to paragraph (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion.

Each Market Buyer shall be charged or credited for Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Losses.

(a) Whenever the Office of the Interconnection has in place appropriate computer hardware, software, and other necessary resources to account for marginal losses in the dispatch of energy and the calculation of Locational Marginal Prices, loss accounting shall be determined on that basis, and the provisions of this Section shall be revised accordingly. Until such time, the following accounting provisions for losses shall apply.

(b) Each Internal Market Buyer that is a Load Serving Entity or purchasing on behalf of a Load Serving Entity shall be credited in an amount equal to its *pro rata* share of the hourly total amounts collected from Transmission Customers either as charges for transmission losses in the PJM Region as specified in Section 3.4.2 or for transmission losses supplied in kind in accordance with Section 3.4.2(c) based on the Locational Marginal Price at the interface where such losses were delivered. This credit shall be determined by the ratio of the Internal Market Buyers total hourly load (net of its operating Behind The Meter Generation, but not to be less than zero), divided by the total hourly load in the PJM Region (net of total operating Behind The Meter Generation).

(c) MAAC Control Zone 500 kV losses shall be allocated to each Electric Distributor that reports hourly net energy flows from metered tie lines in proportion to its hourly load (net of operating Behind The Meter Generation, but not to be less than zero) in the MAAC Control Zone.

(d) 500 kV and 345 kV losses in the PJM West Region shall be allocated to each Electric Distributor that reports hourly net energy flows from metered tie lines in proportion to its hourly load (net of Behind The Meter Generation, but not to be less than zero) in the PJM West Region.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participants real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participants spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participants real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participants spot market purchases or decreases its spot market sales, and (ii) each Market Participants energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participants real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participants spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) The Office of the Interconnection shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyers internal accounting.

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(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, the Office of the Interconnection shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Prices applicable to each relevant generation bus.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Sellers resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time Prices for each generation and load bus in the PJM Region, including the bus at each point of interconnection between PJM and each adjacent Control Area, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be credited for Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Sellers resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Sellers resources, times (ii) the hourly Real-time Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Sellers generation or interface buses, of the revenues at Day-ahead Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time Prices determined as specified herein, net of any debits specified herein for each of the Market Sellers generation or interface buses.

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3.3.2 Control Zone Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Spinning Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Spinning Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Spinning Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Spinning Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Sellers internal accounting.

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3.4 Transmission Customers.

3.4.1 Transmission Congestion.

Each Transmission Customer shall be charged and credited for Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Losses.

(a) Whenever the Office of the Interconnection has in place appropriate computer hardware, software, and other necessary resources to account for marginal losses in the dispatch of energy and the calculation of Locational Marginal Prices, loss accounting shall be determined on that basis, and the provisions of this Section shall be revised accordingly. Until such time, the following accounting provisions for losses shall apply.

(b) Transmission Customers shall be charged for transmission losses in an amount equal to the product of (i) the Transmission Customers megawatt-hours of deliveries using Point-to-Point Transmission Service, times (ii) the appropriate loss factor for deliveries using Point-to-Point Transmission Service, times (iii) the weighted average Day-ahead or Real-time Price, as applicable, for all load buses in the PJM Region. The foregoing average hourly loss factor shall be: (i) determined by the Office of the Interconnection from time to time as conditions affecting losses shall warrant; and (ii) calculated separately for on-peak and off-peak hours on the basis of the average ratio of losses to load served in each such period.

(c) A Transmission Customer may elect to pay for losses in kind, rounded off to the nearest whole megawatt, rather than as specified above if its total deliveries in an hour using Point-to-Point Transmission Service are greater than 200 megawatts. If it so elects, the Transmission Customers specified source for the energy to be delivered using Point-to-Point Transmission Service may be scheduled to supply to the boundary of the PJM Region an amount of energy equal to the delivery schedule plus the amount of losses determined by applying the appropriate hourly loss factor, as specified above, to the delivered amount.

3.4.3 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customers internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or buses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Areas operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Areas operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

3.6 Metering Reconciliation.

3.6.1 Meter Correction Billing.

Metering errors and corrections will be reconciled at the end of each month by a meter correction charge or credit. The monthly meter correction charge or credit shall be determined by the product of the positive or negative deviation in energy amounts, times the weighted average Locational Marginal Price for all load buses in the PJM Region.

3.6.2 Meter Corrections Between Market Participants.

If a Market Participant or the Office of the Interconnection discovers a meter error affecting an interchange of energy with another Market Participant and makes the error known to such other Market Participant prior to the completion by the Office of the Interconnection of the accounting for the interchange, and if both Market Participants are willing to adjust hourly load records to compensate for the error and such adjustment does not affect other parties, an adjustment in load records may be made by the Market Participants in order to correct for the meter error, provided corrected information is furnished to the Office of the Interconnection in accordance with the Office of the Interconnections accounting deadlines. No such adjustment may be made if the accounting for the Operating Day in which the interchange occurred has been completed by the Office of the Interconnection.

3.6.3 500 kV Meter Errors.

Billing cycle accounting for 500 kV transmission losses shall be adjusted to account for errors in meters on 500 kV Transmission Facilities.

3.6.4 Meter Corrections Between Control Areas.

An error between accounted for and metered interchange between a Party in the PJM Region and an entity in a Control Area other than the PJM Region shall be corrected by adjusting the hourly meter readings. If this is not practical, the error shall be accounted for by a correction at the end of the billing cycle. The Market Participant with ties to such other Control Area experiencing the error shall account for the full amount of the discrepancy and an appropriate debit or credit shall be applied equally among all Market Buyers. The Office of the Interconnection will adjust the actual interchange between the other Control Area and the PJM Region to maintain a proper record of inadvertent energy flow. Meter corrections on the 500 kV system between the PJM Region and other Control Areas shall be accounted for through the internal 500 kV system meter error allocation at the end of the billing cycle.

3.6.5 Meter Correction Data.

Meter error data shall be submitted to the Office of the Interconnection not later than noon on the second working day of the Office of the Interconnection after the end of the billing cycle applicable to the meter correction.

3.6.6 Correction Limits.

A Market Participant may not assert a claim for an adjustment in billing as a result of a meter error for any error discovered more than two years after the date on which the metering occurred. Any claim for an adjustment in billing as a result of a meter error shall be limited to bills for transactions occurring in the most recent annual accounting period of the billing Market Participant in which the meter error occurred, and the prior annual accounting period.

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4. RATE TABLE

4.1 Offered Price Rates.

Spot Market Energy, Regulation, Operating Reserve, and Transmission Congestion are based on offers to the Office of the Interconnection specified in this Agreement.

4.2 Transmission Losses.

Average loss factors shall be as specified in the PJM Tariff.

4.3 Emergency Energy Purchases.

The pricing for Emergency energy purchases will be determined by the Office of the Interconnection and: (a) an adjacent Control Area, in accordance with an agreement between the Office of the Interconnection and such adjacent Control Area, or (b) a Member, in accordance with arrangements made by the Office of Interconnection to purchase energy offered by such Member from resources that are not Capacity Resources.

5. CALCULATION OF TRANSMISSION CONGESTION CHARGES AND CREDITS

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses in accordance with Section 9.3, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The basis for the Transmission Congestion Charges shall be the differences in the Locational Marginal Prices between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. The Transmission Congestion Charge for deliveries from each such source shall be the Network Service Users hourly net bill less its hourly net PJM Interchange payments or sales as determined in accordance with Section 3.2.1 or Sections 3.3 and 3.3.1 of this Schedule.

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5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Price at the delivery point or the delivery interface at the boundary of the PJM Region and the Day-ahead Price at the source point or the source interface at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Price at the source point or the source interface at the boundary of the PJM Region. A Transmission Customer shall be credited for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Price at the source point or the source interface at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service. The Transmission Congestion Charge for Market Sellers using point-to-point transmission service for deliveries out of the PJM Region from generating resources within such area shall be the amount of its net bill less the Market Sellers net hourly PJM Interchange payments or sales as determined in accordance with Section 3.3 of this Schedule.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Real-time Price at what would be the delivery interface and the Real-time Price at what would be the source interface, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery interfaces in accordance with an applicable load flow study.

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5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the interface buses between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by the Office of the Interconnection each hour will be the aggregate net amounts determined as specified in this Schedule. The Office of the Interconnection shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights Auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in locational marginal prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in locational marginal prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights Auction.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in paragraph (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Price at the point of delivery is higher than the Day-ahead Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Price at the point of receipt is higher than the Day-ahead Price at the point of delivery. The Day-ahead Prices determined for purposes of this subsection shall exclude the Locational Marginal Price adjustments for third-party transmission losses provided by Section 9.3.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Price at the point of delivery is higher than the Day-ahead Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Price at the point of receipt is higher than the Day-ahead Price at the point of delivery. The Day-ahead Prices determined for purposes of this subsection shall exclude the Locational Marginal Price adjustments for third-party transmission losses provided by Section 9.3.

(d) A Financial Transmission Right, or the right to Transmission Congestion Credits attributable to a Financial Transmission Right, may be sold or otherwise transferred by agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(e) Network Service Users and Firm Transmission Customers that take service that sinks in new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in new PJM zones that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) All Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

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(In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of
i Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the
i Network Service User losing the load to the Network Service User that is gaining the Network Load.
)

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is gaining the Network Load may request Financial Transmission Rights commensurate with the amount of the Network Load gained.

(g) At least one month prior to the integration of a new zone into the PJM interchange energy market, Network Service Users and Firm Transmission Customers that take service that sinks in the new zone shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, mitigation) rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

(1) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(d) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

(2) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

(3) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

(4) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under paragraph (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

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The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customers share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A target allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Rights. Each Financial Transmission Right shall be multiplied by the Day-ahead Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Locational Marginal Price at the delivery point(s) minus the Locational Marginal Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Price of a Zone is calculated as the sum of the Day-ahead Price of the buses that comprise the Zone multiplied by the percent of annual peak load assigned to each node. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR

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Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total target allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the target allocations associated with all of the Network Service Users or Transmission Customers Financial Transmission Rights. The Day-ahead Prices determined for purposes of this section shall exclude the Locational Marginal Price adjustments for third-party transmission losses provided by Section 9.3.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the target allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the target allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its target allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 Distribution of Excess Congestion Charges.

(b) If the total of the target allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its target allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total target allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total target allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period. After Auction Revenue Right deficiencies are satisfied, any remaining excess Transmission Congestion Charges shall be distributed to Network Service Users and Transmission Customers purchasing Firm Point-to-Point Transmission Service in proportion to their Demand Charges for Network Service and their charges for Reserved Capacity for Firm Point-to-Point Transmission Service over such period.

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5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the Members (or the Office of the Interconnection on behalf of the Members) and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.

(b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each East Transmission Owner with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis.

6. MUST-RUN FOR RELIABILITY GENERATION

6.1 Introduction.

The following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that (a) is a generation resource for which construction commenced before July 9, 1996, and (b) as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.

6.2 Identification of Facility Outages.

Not later than one hour prior to the deadline specified in Section 1.10.1 of this Schedule, the Office of the Interconnection shall identify on the PJM Open Access Same-Time Information System any facility outage or other system condition which it has determined may give rise to a transmission constraint that may require, in order to maintain system reliability, the dispatch of one or more generation resources that otherwise would not be dispatched based on the merits of their offers to the PJM Interchange Energy Market.

6.3 Dispatch for Local Reliability.

6.3.1 Request and Dispatch.

In addition to the dispatch of generation by the Office of the Interconnection to maintain reliability on transmission facilities monitored by it, a Member that owns or leases with rights equivalent to ownership local Transmission Facilities, as defined in this Agreement, the West Transmission Owners Agreement, or the East Transmission Owners Agreement and that operates a local control center in accordance with Section 11.3.3 of this Agreement or a Market Operations Center in accordance with Section 1.7.5 of this Schedule may request the Office of the Interconnection to dispatch generation in order to maintain reliability on any such local Transmission Facilities that are not then monitored by the Office of the Interconnection, subject to the rules and procedures in Section 6.3.2 and the PJM Manuals. The Office of the Interconnection shall dispatch generation to maintain reliability on such local Transmission Facilities by incorporating the facilities in the State Estimator program described in Section 2.3 as set forth below, unless the Office of the Interconnection determines that such dispatch would adversely affect reliability in the PJM Region or would otherwise not be in accordance with Good Utility Practice.

6.3.2 Designation of Local Transmission Facilities.

The following rules and procedures shall apply to a Member request that the Office of the Interconnection dispatch generation on one or more local Transmission Facilities that are not then directly monitored by the Office of the Interconnection.

(a) The local Transmission Facilities that are the subject of the request for monitoring and dispatch control must be among the facilities that comprise the Transmission System under the PJM Tariff and must meet the PJM Reliability Planning Criteria set forth in the PJM Manuals;

(b) The Member shall provide modeling information for such local Transmission Facilities and provide sufficient telemetry to the Office of the Interconnection such that power flows are observable by the State Estimator program described in Section 2.3;

(c) The request for monitoring and dispatch control of local Transmission Facilities shall constitute a request that such local Transmission Facilities become and remain monitored by the Office of the Interconnection and subject to its dispatch control for a period of not less than one year;

(d) Requests under this Section for monitoring and dispatch control of local Transmission Facilities may be made only annually pursuant to the procedures set forth in the PJM Manuals;

(e) The Office of the Interconnection shall post all requests for monitoring and dispatch control of local Transmission Facilities made under this Section on the PJM Internet site; and

(f) The Member shall comply with all other operating procedures established by the Office of the Interconnection regarding dispatch for local reliability as set forth in the PJM Manuals.

6.3.3 Transition Procedures for Local Transmission Facilities under the Monitoring Responsibility and Dispatch Control of the Office of the Interconnection as of June 1, 2002.

The Office of the Interconnection shall determine whether local Transmission Facilities under its monitoring responsibility and dispatch control as of June 1, 2002 meet the PJM Reliability and Planning Criteria. Members with such local Transmission Facilities that do not meet the PJM Reliability Planning Criteria must either (1) remove the local Transmission Facilities from the dispatch control and monitoring responsibility of the Office of the Interconnection within 60 days of notification by the Office of the Interconnection of its determination that the local Transmission Facilities do not meet the PJM Reliability and Planning Criteria; or (2) commit, at their own cost and by a completion date agreed to by the Office of the Interconnection and the Member, to reinforce the local Transmission Facilities to enable the local Transmission Facilities to meet the PJM Reliability and Planning Criteria. This commitment to reinforce the local Transmission Facilities is subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any

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necessary state or local siting, construction and operating permits, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, provided that, in the event that a Member cannot reinforce the local Transmission Facilities due to the unavailability of required financing, the local Transmission Facilities must be removed from the monitoring responsibility and dispatch control of the Office of the Interconnection within 60 days of the determination that required financing is unavailable. The local Transmission Facilities will remain under the monitoring and dispatch control of the Office of the Interconnection during the construction of the reinforcements.

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) Except as specified below, if, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped at the levels specified below. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the transmission limit affects the schedule of the affected resource, and otherwise shall be capped for the entire Operating Day. The energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the offer price of such resource.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified below. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. The energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) Offer price caps shall not be applicable to generation resources used to relieve the Western, Central and Eastern reactive limits in the PJM Control Area. In addition, offer price caps shall not be applicable to generation resources used to relieve any other transmission limit as to which the FERC has determined that offer price caps shall not be applicable.

(e) Offer price caps shall be suspended for any transmission limit(s) for any hour in which there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s). Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by this section. Such proposals shall take effect only upon Commission acceptance or approval.

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Vice President, Government Policy
IssuedOn: July 16, 2004
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. EL03-236, issued May 6, 2004, 107 FERC 61,112.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) The incremental operating cost of the generation resource as determined in accordance with Schedule 2 of this Agreement and the PJM Manuals, plus 10% of such costs;

(iii) For a unit that is offer capped for 80 percent or more of its run hours, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of this Agreement and the PJM Manuals, plus the higher of $40 per megawatt-hour or the unit-specific going forward costs of the affected unit as reflected in an agreement entered pursuant to subparagraph (iv), below; or

(iv) An amount determined by agreement between the Office of the Interconnection and the Market Seller, provided that, if the Office of the Interconnection and the Market Seller cannot reach agreement after 60 days from the commencement of negotiations, then the Market Seller may submit the rates, terms, and conditions of its proposed offer cap to the Commission for resolution.

(b) For purposes of section 6.4.2(a)(iii), a unit shall qualify for the specified offer cap if it was offer capped for 80 percent or more of its run hours over the course of the 12 month period ending December 31 of the calendar year preceding the calendar year in which the offer is submitted.

(c) For purposes of section 6.4.2(a)(iii), the unit-specific going forward costs determined by agreement between the Office of the Interconnection and the Market Seller shall include only the costs included in the Deactivation Avoidable Cost Rate, excluding costs associated with the Avoidable Project Investment Recovery Rate (APIR), set forth in section 115 of the PJM Tariff. Any costs that would be capitalized according to generally accepted accounting principles, associated carrying costs, or other fixed costs shall not be included. The agreement shall further provide that (i) in order for such costs to qualify for inclusion in the amounts determined by the agreement, the Market Seller must agree to provide to PJM relevant cost data concerning fuel, operating and maintenance, and other avoidable costs, (ii) the maintenance practices and incurrence of expense at the unit shall be subject to audit by the Office of the Interconnection, and (iii) the unit owner agrees to operate the unit in accordance with Good Utility Practice.

(d) Any agreement entered pursuant to section 6.4.2(a)(iv) shall be filed with the Commission and shall be effective only upon acceptance of the agreement for filing by the Commission.

7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

7.1 Auctions of Financial Transmission Rights.

Annual and periodic auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section.

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. EL03-236-000, issued May 6, 2004, 107 FERC 61,112. This tariff sheet is subject to further modifications and clarifications pursuant to order of the Federal Energy Regulatory Commission, Docket No. EL03-236, issued January 25, 2005, 110 FERC 61,053.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of the annual auction and (2) the one-month period following the date that the monthly auction is conducted. With the exception of FTRs allocated pursuant to Section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to Section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection shall offer for sale in the auction any remaining Financial Transmission Rights capability for the month after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to Section 5.2.2(e) and the award of Financial Transmission Rights pursuant to Section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction. An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participants credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to Section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April May) preceding the start of the PJM planning period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly Financial Transmission Rights auctions shall be held. The bid and offer period shall open at 12:00 midnight (Eastern Prevailing Time) on the thirteenth (13th) business day preceding the month for which Financial Transmission Rights are being auctioned and shall close at 5:00 PM (Eastern Prevailing Time) on the tenth (10th) business day preceding the month for which Financial Transmission Rights are being auctioned.

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.2 Financial Transmission Rights Characteristics.

7.2.1 Reconfiguration of Financial Transmission Rights.

Through an appropriate linear programming model, the Office of the Interconnection shall reconfigure the Financial Transmission Rights offered or otherwise available for sale in any auction to maximize the value to the bidders of the Financial Transmission Rights sold, provided that any Financial Transmission Rights acquired at auction shall be simultaneously feasible in combination with those Financial Transmission Rights outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum MW quantities of the bids and offers, select the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

7.2.2 Specified Receipt and Delivery Points.

Auction bids for annual Financial Transmission Rights Obligations may specify as receipt and delivery points any combination of hubs, Zones, aggregates, generators, and interface buses. Auction bids for annual Financial Transmission Rights Options may specify as receipt and delivery points such combination of hubs, Zones, aggregates, generators, and interface buses as the Office of the Interconnection shall allow from time to time as set forth in its FTR business manual. Auction bids for monthly Financial Transmission Rights may specify any combination of receipt and delivery buses represented in the State Estimator model for which the Office of the Interconnection calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the PJM Region to locations inside such region, from locations within the PJM Region to locations outside such region, or to and from locations within the PJM Region.

7.2.3 Transmission Congestion Charges.

Financial Transmission Rights shall entitle holders thereof to credits only for Transmission Congestion Charges, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the Office of the Interconnection.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Right sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Section 5.2.2 (e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 On-Peak, Off-Peak and 24-Hour Periods.

On-peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auction. On-Peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the PJM Manuals. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for an on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offer or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Section 7.2.2 and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period, market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of the bidding period each month, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Section 7.4 of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determine by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of a monthly auction, or annual auction round, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay or be paid the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual and monthly auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

7.4.2 Auction Revenue Rights.

(a) On an annual basis by such deadline established by the Office of the Interconnection, the allocation of Auction Revenue Rights shall be performed using a two stage allocation process. In the first stage of the allocation process, each Network Service User may request Auction Revenue Rights from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone. The historical reference year for all Zones shall be 1998, except that the reference year shall be 2002 for the Allegheny Power and Rockland Electric Zones, and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For each Zone, the Office of the Interconnection shall determine a set of eligible generation sources based on the historical reference year and assign a pro rata amount of megawatt capability from each resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the resource that has been assigned to the Network Service User. Each Auction Revenue Right shall be to the aggregate load busses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the area comprised of the PJM West Region and PJM Control Area. In the first stage of the allocation process, the sum of each Network Service Users allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service Users peak load for that Zone as determined under Section 34.1 of the Tariff. The sum of each Network Service Users Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the Network Service Users transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff.

(b) In the second stage of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of four rounds with 25 percent of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only zones, generators, hubs and external interface buses. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load busses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the area comprised of the PJM West Region and PJM Control Area. The sum of each Network Service Users Auction Revenue Rights requests in each allocation round for each Zone must be equal to or less than 25 percent of the difference between the Network Service Users peak load for that Zone as determined under Section 34.1 of the Tariff and its Auction Revenue Right Allocation from the first stage of the allocation process for that Zone.

(c) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service Users Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(d) Each Transmission Customer receiving firm Point-to-Point Transmission Service shall specify whether it wishes to receive Auction Revenue Rights. If the Transmission Customer elects to request Auction Revenue Rights, the customer may do so by specifying such selection in the second stage of the allocation process. The Auction Revenue Rights that the Transmission Customer may request in each round must be equal to or less than 25 percent of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer has firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the transmission service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the transmission service request.

(e) All Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

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7.4.3 Target Allocation of Auction Revenue Right Credits.

A target allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right Auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total target allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily target allocations associated with all of the entitys Auction Revenue Rights.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily target allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights target allocations applicable for that day shall be compared to the total revenues of the monthly Financial Transmission Rights auction (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the planning period). If the total of the target allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its target allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the target allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights target allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

7.5 Simultaneous Feasibility.

The Office of the Interconnection shall make the simultaneous feasibility determinations specified herein using appropriate powerflow models of contingency-constrained dispatch. Such determinations shall take into account outages of both individual generation units and transmission facilities and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction that are not inconsistent with the determination of the deliverability of Capacity Resources under the Reliability Assurance Agreement or Reliability Assurance Agreement-West. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient revenues from Transmission Congestion Charges to satisfy all Financial Transmission Rights obligations for the auction period under expected conditions and to ensure that there are sufficient revenues from the annual Financial Transmission Right Auction to satisfy all Auction Revenue Rights obligations.

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8. INTERREGIONAL TRANSMISSION CONGESTION

MANAGEMENTPILOT PROGRAM

8.1 Introduction.

The following procedures shall govern the redispatch of generation to alleviate transmission congestion on selected pathways on the transmission systems operated by the Office of the Interconnection and the New York ISO (NYISO). The procedures shall be used solely when, in the exercise of Good Utility Practice, the Office of the Interconnection or NYISO determines that the redispatch of generation units on the others transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures.

8.2 Identification of Transmission Constraints.

(a) On a periodic basis determined by the Office of the Interconnection and NYISO, the Office of the Interconnection and NYISO shall identify potential transmission operating constraints that could result in the need to use Transmission Loading Relief or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation on the others system.

(b) In addition to the identification of such potential transmission operating constraints, the Office of the Interconnection and NYISO shall identify generation units on the others system, the redispatch of which would alleviate the identified transmission constraints.

(c) From the identified transmission constraints, the Office of the Interconnection and NYISO shall agree in writing on the transmission operating constraints and redispatch options that shall be subject to Section 8 of this Schedule until otherwise agreed. In reaching such agreement, the Office of the Interconnection shall endeavor reasonably to limit the number of transmission constraints that are subject to Section 8 of this Schedule so as to minimize potential cost shifting among market participants in the control area of NYISO and the PJM Region resulting from the redispatch of generation under Section 8 of this Schedule. The Office of the Interconnection shall post the transmission operating constraints that are subject to Section 8 of this Schedule on PJMs internet site.

8.3 Redispatch Procedures.

If (i) a transmission constraint subject to Section 8 of this Schedule occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) the Office of the Interconnection or NYISO, as applicable, has determined that it must either use Transmission Loading Relief or other emergency procedures, then (iii) the affected entity may request the other to redispatch one or more of the previously identified generation units to alleviate the transmission constraint. Upon such request, the Office of the Interconnection or NYISO, as applicable, shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with Good Utility Practice.

8.4 Locational Marginal Price.

(a) In the event that the Office of the Interconnection requests that NYISO redispatch generation under this Section 8, the Office of the Interconnection shall include the generators offer price (in the NYISO energy market) in a reference price at the appropriate NYISO generator bus in the PJM State Estimator and in the calculation of Real-time Prices and shall include the cost of any applicable startup and no-load fees in the cost of Operating Reserves for the Real-time Energy Market; provided, however, that if the energy offer price plus any applicable start-up or no-load fees exceeds $1000/megawatt-hour, then the entire cost of the redispatch will be included in the cost of Operating Reserves for the Real-time Energy Market and will not be included in the Real-time Prices calculation.

(b) The redispatch of a generator by the Office of the Interconnection in response to a request from NYISO under Section 8 of this Schedule shall not be included in the determination of Locational Marginal Prices under Section 2 of this Schedule.

8.5 Generator Compensation.

Generators that have increased or decreased generation output above or below the level that would otherwise represent the economic dispatch level and as a result of a request made pursuant to this Section 8 (the MWh Adjustment) shall be compensated based on the following:

(a) For a positive MWh Adjustment:

Payment to Generator = MWh Adjustment * (unit offer price marginal price at the generator bus) + any applicable start-up or no-load costs not recovered by the marginal price

(b) For a negative MWh Adjustment:

Payment to Generator = |MWh Adjustment| * (marginal price at the generator bus unit offer price) + any applicable start-up or no-load costs not recovered by the marginal price

8.6 Settlements.

(a) If NYISO redispatches generation under this Section 8, then the Office of the Interconnection shall include in its monthly accounting and billing a payment to NYISO for the costs of such redispatch as determined in accordance with Section 8.5.

(b) If the Office of the Interconnection redispatches generation under this Section 8, then it shall include in its monthly accounting and billing a credit to each redispatched generator calculated in accordance with Section 8.5. The Office of the Interconnection shall invoice NYISO and NYISO shall collect from its market participants and pay to the Office of the Interconnection on behalf of such market participants an amount equal to all such credits to generators.

(c) Unless there is a separate emergency energy transaction accompanying any generation adjustment under this Schedule 8, there shall be no adjustment in interchange between PJM and NYISO as a result of redispatch under this Schedule 8. In the event that an emergency energy transaction accompanies any generation adjustment, compensation for such transaction shall be at the rates for emergency purchases and sales which have been approved by the FERC, as they may be amended from time-to-time.

8.7 Effective Date

Section 8 of this Schedule shall become effective only upon (a) approval or acceptance by the Federal Energy Regulatory Commission and (b) approval or acceptance by the Federal Energy Regulatory Commission of any comparable amendments to rate schedules of NYISO, if required.

9. COMMONWEALTH EDISON ZONE MARKET INTEGRATION

DURING THE COMED INTEGRATION PHASE

9.1 Introduction

The following procedures shall govern the application of the PJM Interchange Energy Market and related rules to the Zone of Commonwealth Edison Company and Commonwealth Edison Company of Indiana (ComEd) during the period (ComEd Integration Phase) beginning upon the date that the ComEd Zone is added to the PJM West Region and concluding upon the date that the zone of American Electric Power Company is added to the PJM West Region. During the ComEd Integration Phase, the zone of ComEd shall be a separate control area (Northern Illinois Control Area) from the remainder of the PJM Region (PJM Control Area). The PJM Interchange Energy Market shall encompass both control areas, and all other provisions of this Agreement and its Schedules and Attachments shall apply to the Northern Illinois Control Area during the ComEd Integration Phase except to the extent expressly modified below.

9.2 Generation Transfer Pathway

(a) A generation transfer pathway will be used to facilitate the application of the PJM Interchange Energy Market to the Northern Illinois Control Area. Transmission reservation holders with a valid existing transmission service reservation on the OASIS of American Electric Power Company (Intermediate Transmission Provider), where such reservation has a point of receipt or delivery in the Northern Illinois Control Area and a point of receipt or delivery in the PJM Control Area (in either direction) may allocate all or part of such reservation, in accordance with the following procedures, to the Office of the Interconnection for its exclusive use in administering the PJM Interchange Energy Market and conducting the security-constrained economic dispatch of resources to serve the loads of the PJM Region.

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(b) Intermediate Transmission Provider reservation holders may submit requests on the Transmission Providers OASIS to allocate firm transmission service to the pathway for monthly or annual periods, by no later than 11:00 a.m. eastern prevailing time (EPT) on the day before the allocation is to commence. Monthly allocations shall commence at 00:00 EPT on the first day of a calendar month and end at 00:00 EPT on the first day of the next consecutive calendar month. Annual allocations shall commence at 00:00 EPT on the first day of a calendar year and end at 00:00 EPT on the first day of the next consecutive calendar year. All such requests must be pre-confirmed, and must identify the reservation holders existing reservation from the Intermediate Transmission Provider OASIS. The allocation may be for a quantity less than or equal to the existing Intermediate Transmission Provider reservation. Service allocated to the Office of the Interconnection may not be recalled by the reservation holder, or scheduled or redirected by the reservation holder on the Intermediate Transmission Providers system, for the quantity or term of the allocation, but may be relied upon by the reservation holder to qualify a resource located in either of the two control areas in the PJM region during the Interim Period as a Capacity Resource to serve load in the other control area of the PJM Region. The Office of the Interconnection shall adopt such procedures as necessary to coordinate with the Intermediate Transmission Provider to ensure that the foregoing provision is enforced. The reservation holder remains responsible for all costs, charges, and obligations (financial or otherwise) under its transmission service agreement with the Intermediate Transmission Provider (excluding transmission losses, which shall be provided by the Office of the Interconnection in-kind pursuant to section 9.3 hereof) relating to the service being allocated.

(c) The allocated transmission service shall be under the exclusive use and control of the Office of the Interconnection and shall be employed to further its duties and responsibilities in accordance with the Operating Agreement, including, without limitation, the principles of section 7.7(i) of such Agreement. The Office of the Interconnection shall establish a dynamic schedule with the Intermediate Transmission Provider in either direction between the Northern Illinois Control Area and the PJM Control Area under the allocated transmission service to support the security-constrained, economic dispatch of resources to serve the loads of the PJM Region. In each direction, the dynamic schedule shall be subject to the quantity, duration, and priority of the transmission service allocated in such direction, and the dynamic schedule may be curtailed or limited by the Intermediate Transmission Provider in accordance with the terms and conditions of its governing tariff. The Office of the Interconnection shall treat curtailments of or limitations on the dynamic schedule in the same manner as transmission constraints internal to the PJM Region.

(d) Transmission Customers may not schedule as a single transmission transaction with the Office of the Interconnection point-to-point transmission service with a point of receipt (or delivery) at the border of the Northern Illinois Control Area and any third-party control area and a corresponding point of delivery (or receipt) at the border of the PJM Control Area and any third-party control area. Such service shall require (in addition to any necessary service from the Office of the Interconnection) transmission service from the Intermediate Transmission Provider or other appropriate transmission provider.

9.3 Transmission Loss Recovery

The Office of the Interconnection shall be responsible for arranging for the generation of energy in, and its delivery from, the PJM Region to satisfy Intermediate Transmission Provider tariff requirements for recovery of transmission losses associated with allocated transmission service. The Office of the Interconnection shall apply the loss factors from the Intermediate Transmission Providers tariff (including any variances in such loss factors between on-peak and off-peak periods, as defined in such tariff) to the quantity of energy dynamically scheduled to calculate the additional energy to be provided to the Intermediate Transmission Provider for in-kind satisfaction of transmission losses. The Office of the Interconnection shall adjust locational marginal prices in the PJM Region based on the adjusted dispatch necessary to generate the energy for Intermediate Transmission Provider losses and to compensate generators for supplying such additional energy.

9.4 Financial Transmission Rights

(a) Financial Transmission Rights shall be allocated to Network Service Users and Firm Transmission Customers that take service that sources or sinks in the Northern Illinois Control Area in accordance with the provisions of section 5.2.2(f) and (g) of this Schedule applicable to new PJM zones; provided that, solely for purposes of allocating Financial Transmission Rights in the ComEd Zone during the term of the Phase-In Period, as such term is defined in Schedule 17 of the PJM West RAA, Financial Transmission Rights shall be allocated in the ComEd Zone in two stages: first, to all Firm Point-to-Point Transmission Customers and to all Network Integration Transmission Service paths for which the source point is a Capacity Resource or for which the original transmission service request identified a specific source; and, second, to the extent Financial Transmission Rights remain available after such allocation, to Network Integration Transmission Service paths for which there is no specifically designated source. The sum of the FTRs requested by a Load-serving Entity in both stages may not exceed the Load-serving Entitys Network Integration Transmission Service peak load. FTR requests in the first stage for which the source point is a Capacity Resource may not exceed the capability of the resource, and requests in such stage that are based on reserved Network service from a specifically identified source must be from such source and may not exceed the capacity of such reservation. The Office of the Interconnection shall identify in the PJM Manuals appropriate points of interconnection between the Northern Illinois Control Area and adjacent control areas for purposes of designating points of receipt or delivery for Financial Transmission Rights. If a Network Service User is the buyer under a wholesale supply contract that specifies the Network Service Users load as the delivery point, the Network Service User may elect to assign to the seller under such wholesale supply contract, if such seller chooses to assume such right, the right to nominate FTRs as described above, solely for purposes of allocating Financial Transmission Rights in the ComEd zone during the Phase-In Period. Following the Phase-in Period, Financial Transmission Rights (or Auction Revenue Rights, as applicable) shall be allocated in accordance with section 5.2.2.

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(b) Transmission reservation holders that allocate firm transmission service to the Office of the Interconnection in accordance with this section 9 may request Financial Transmission Rights (solely as obligations, and not as options) in return for such allocation, and such request shall be granted by providing Financial Transmission Rights between the border of the Northern Illinois Control Area Zone and the border of the PJM Control Area in the amount requested, provided that the request is for a megawatt amount equal to or less than the megawatt amount of the transmission service so allocated. Such Financial Transmission Rights shall be in the same direction as the allocated transmission service and for a term equal to the term of the transmission service allocation. Financial Transmission Rights from the border points for the allocated transmission service to the source or sink points in the PJM Region shall be granted to the extent not previously granted and to the extent simultaneously feasible in accordance with section 7.5.

9.5 Ancillary Services

For purposes of applying the provisions of sections 3.2.2, 3.2.3, and 3.2.3A pertaining to regulation, operating reserves, and spinning reserves, the Northern Illinois Control Area shall be deemed a Control Zone. The offer of a resource located in the Northern Illinois Control Area for regulation, operating reserves, or spinning reserve shall be cost-based, unless and until market-based pricing is authorized for such service in the Northern Illinois Control Area.

10. PJM-FE INTERREGIONAL TRANSMISSION

CONGESTION MANAGEMENT

(a) The Office of the Interconnection may from time to time enter into agreements with FirstEnergy Solutions Corp. (FES) providing procedures for the redispatch of generation resources to alleviate transmission congestion, for use solely when, in the exercise of Good Utility Practice, the Office of the Interconnection determines, absent any other effective market-based solutions available to it, that the redispatch of generation units on the FE transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures. The Office of the Interconnection is authorized to incur costs as described herein on behalf of the Market Participants to obtain such redispatch, and shall allocate and recover such costs as described herein. Such cost recovery shall be limited to the costs incurred by the Office of the Interconnection pursuant to an agreement providing for the redispatch of generation resources at FEs Sammis Generating Station to alleviate actual or contingency overloads on the PJM Wylie Ridge transformers (the #5 transformer or the #7 transformer) or the PJM Sammis-Wylie Ridge 345kV transmission line. The costs the Office of the Interconnection is authorized to incur and to recover hereunder to obtain such redispatch shall be those necessary to compensate for reasonable opportunity costs incurred by FE in connection with such redispatch as calculated based upon the cost of the energy that could have been produced by the Sammis units as developed in accordance with the PJM Cost Development Manual, as well as costs incurred by FE related to reduced efficiency caused by cycling its units at the request of the Office of the Interconnection.

(b) Any payments to FE associated with redispatch under section 10(a) shall be included in the cost of Operating Reserves for the Real-time Energy Market, in accordance with Section 3.2.3(g) of this Schedule 1.

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PJM Emergency Load Response Program

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EMERGENCY LOAD RESPONSE PROGRAM

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event.

EFFECTIVE DATE

The program will be effective beginning December 1, 2004 , and will remain in effect until December 31, 2007. The PJM Market Monitoring Unit will review the program following each summer period.

PARTICIPANT QUALIFICATIONS

Two primary types of distributed resources are candidates to participate in the PJM Emergency Load Response Program:

On Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

PJM membership is required to participate in the Emergency Load Response Program. Special membership provisions have been established for program participants, as described below. Any existing PJM Member may as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.*** However, for the special members the $5,000 annual member fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications.

Special Members are limited to be PJM market sellers;

Voting privileges and sector designation are waived;

Thirty day notice for waiting period is waived;

Requirement for 24/7 control center coverage is waived;

No PJM-supported user group capability is permitted.

To participate in the emergency program, the distributed resource must:

Be capable of reducing at least 100 kW of load

Be capable of receiving PJM notification to participate during emergency conditions.

METERING REQUIREMENTS

The Load Response Program participants must have metering equipment that provides integrated hourly kWh values on an EDC account basis, that either meets the EDC requirements for accuracy or has a maximum error of two percent over the full range of the meter (including Potential Transformers and Current Transformers). The metering requirements can be met using either of the following two methods:

Metering that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator).

Metering that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an EDC account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the CSP and verified by PJM with the EDC.

The installed meter must be one of the following:

EDC-owned hourly meter,

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read electronically by PJM, or Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read by the customer (or the CSP), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

REGISTRATION

Participants must complete the PJM Emergency Load Response Program Registration Form that is posted on the PJM web site (www.pjm.com). The following general steps will be followed:

The participant completes the PJM Emergency Load Response Program registration form located on the PJM web site.

PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate LSE and EDC whether the load reduction is under other contractual obligations. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract. The EDC and LSE have ten (10) business days to respond or PJM assumes acceptance.

PJM informs the requesting participant of acceptance into the program and notifies the appropriate LSE and EDC of the participants acceptance into the program.

Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

EMERGENCY OPERATIONS

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of ALM Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM web site, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Operational procedures are described in detail in the ***PJM Manual for Emergency Operations*** .

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VERIFICATION

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for the hour prior to the event, as well as every hour during the event.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM. All load reduction data are subject to PJM Market Monitoring Unit audit.

MARKET SETTLEMENTS

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided could be less than, equal to, or greater than the kW amount declared on the Emergency Load Response Program Registration form.

PJM pays the higher of the applicable Locational Marginal Price (LMP) or $500/MWh to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for loses times the higher of the applicable Locational Marginal Price (LMP) otherwise in use for settlement of the given load or $500/MWh.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time. An Active Load Management (ALM) Customer may participate in the Load Response program during ALM events as long as the customers ALM contract explicitly excludes payment or credit for energy not consumed during ALM events. If the LSE that submitted the customer for ALM credit indicates that the customer is not eligible for simultaneous credit under the Load Response program and ALM is called for concurrent with the Load Response program, then payments will be made to the customer according to the Load Response program only for the time during which ALM obligations were not in effect. Any response in excess of the contracted ALM amount will be

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compensated under the Load Response program for the entire duration of response. Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing.***

REPORTING

Actual load reductions will be added back for the purpose of peak load calculations for capacity.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site.

On an annual basis PJM will prepare a report that summarizes the status of the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.

NON - HOURLY METERED CUSTOMER PILOT

PJM will also consider customers without hourly metering for participation in a pilot program for up to two years per customer, provided the customers or their representatives propose an alternate method for measuring hourly load reductions. Alternate measurement mechanisms will be approved by PJM on a case-by-case basis. Participation in the non-hourly metered customer pilot will be limited to 100MW aggregate load reduction over the PJM region and across all load response programs, and with the sole exception of the requirement for hourly metering, will be subject to the same rules and procedures as the applicable load response program in which the customer has enrolled. Following the 2-year pilot period, each alternate method must be approved through the normal PJM stakeholder process in order to continue to be used.

LOAD RESPONSE EXAMPLE

The scenario described below is intended to illustrate how PJM would calculate the payments made to participants upon implementation of the Emergency Load Response Program. The example assumes the customer has acquired the appropriate form of PJM membership, completed the appropriate PJM Load Response Program Registration Form, and been approved for participation by PJM.

The following is a typical timeline by which a load could respond to PJM emergency procedures:

One day Prior to Operating Day:

2230 PJM calls Max Emergency generation into the capacity for the next day. This information is posted on the PJM OASIS, web site, eDATA, etc.

Operating Day:

1300 PJM Issues Max Emergency Generation. This information is posted on the PJM OASIS, PJMs web site, eDATA, etc.

1330 PJM begins to recall off-system sales.

1400 PJM loads Max Emergency generation, begins to purchase emergency energy, and implements the Emergency Load Response Program.

1800 PJM cancels and begins unloading Max Emergency generation, curtails emergency purchases, and cancels the Emergency Load Response Program.

Customer ABC has a typical load of 500kW. Of this load, approximately 150kW may be shut down within one hour during emergency conditions. At 1400, Customer ABC receives notification that PJM has implemented the Emergency Load Response Program. Customer ABC immediately begins the process of disconnecting the applicable load. All such load is disconnected by 1445. Customer ABC receives notification at 1800 that PJM has cancelled implementation of the Emergency Load Response Program and the load is reconnected to the system at 1830.

The metered load for those hours following implementation of the program is compared to the hour preceding implementation to determine the actual reduction. The following table illustrates how the customer metering and associated payments might appear:

Hour Ending	Integrated Load (kWh)	Delta (kWh)	Integrated Zonal LMP ($/MWh)	Payment ($)
1400	495	0	1000	0
1500	467.5	27.5	1000	27.50
1600	345	150	1000	150.00
1700	348	147	850	124.95
1800	345	150	400	75.00
1900	420	75	300	0

PJM Economic Load Response Program

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INTRODUCTION

PJM Load Response Program

This program is designed to provide an incentive to end-use customers or curtailment service providers to enhance the ability and opportunity for reduction of consumption when PJM Locational Marginal Prices (LMP) prices are high. * The program purposefully incorporates incentives that are greater than strict economics would provide for the same curtailment. This departure from economics is justified to overcome initial barriers to end-use customer load response. This program is not intended to be a permanent fix to the lack of load response seen in the PJM markets today. The designers of this program contemplate that when the existing market barriers are removed and end-use customers are better able to respond to real time prices, the need for this program and others like it will disappear. Until that happens, however, programs like this are necessary for fully functioning markets.

Economic Load Response Program - Real Time

This option will provide a mechanism by which any qualified Load Serving Entity (LSE) or Curtailment Service Provider (CSP) may offer end-use customers the opportunity to, or end-use customers that are PJM members independently may choose to, reduce load they draw from the PJM system during times of high prices and receive payments based on real time LMP for the reductions.

The program will be effective June 1, 2002, and will remain in effect until December 1, 2004. At that time, the program will be terminated unless it is extended by a two-thirds sector vote of the Members Committee.

Economic Load Response Program - Day Ahead

This option will provide a mechanism by which any qualified LSEs or CSPs may offer end-use customers the opportunity to, or end-use customers that are PJM members independently may choose to, commit to a reduction of load they draw from the PJM system in advance of real time operations and receive payments based on day-ahead LMP for the reductions.

The program will be effective June 1, 2002, and will remain in effect until December 1, 2004. At that time, the program will be terminated unless it is extended by a two-thirds sector vote from the Members Committee.

This program is not intended to be a replacement for Active Load Management (ALM), but rather an additional means by which distributed generation resources and end-use customers capable of reducing load can participate in PJM operations and markets.

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The program is applicable to both the PJM and PJM West control areas.

For the purposes of the Economic Load Response Program LMP refers to the hourly integrated LMP.

ECONOMIC LOAD RESPONSE PROGRAM REAL TIME

EFFECTIVE PERIOD OF PROGRAM

The program will be effective December 1, 2004, and will remain in effect until December 31, 2007. At that time, the program will be terminated unless it is extended by a two-thirds sector vote of the Members Committee.

PARTICIPANT QUALIFICATIONS

Two primary types of distributed resources are candidates to participate in the PJM Economic Load Response Program:

On-Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reduction

A participant that has the ability to reduce a measurable and verifiable portion of its load as metered on an Electric Distribution Company (EDC) account basis.

The Economic Load Response Program is intended to encourage broad participation in economic load reductions by any hourly-metered curtailable loads. PJM membership is required to participate in the Economic Load Response Program. Special membership provisions have been established for certain program participants, as described below any existing PJM Member may act as an agent for non-members in which case the agent will be the CSP for the non-member. A CSP may act on behalf of PJM Members, non-members or itself (if a PJM member and end-use customer). All payments are made to the PJM Member. Participants must become signatories to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (PJM Operating Agreement), as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.*** *However, for special members the $1,500 application fee and liability for Member defaults are waived, along with the following other modifications:*

Special members shall pay an annual membership fee of $500 plus 10% of each payment owed by PJM for a load reduction event up to a total of $5,000 in a calendar year. Special members whose contributions toward the annual membership fee equal $5,000 under this program shall nonetheless retain the status of special members and may not convert to full membership in the same year;

Special members are limited to participating in the PJM markets as Market Sellers, which means that they are qualified only for the Economic Load Response Program Real Time;

Voting privileges and sector designation are waived;

Thirty day notice for waiting period is waived;

Requirement for 24/7 control center coverage is waived;

No PJM-supported user group is permitted.

Effective on the start of any calendar year, a special member may convert a pre-existing special membership to a full membership subject to all PJM rules governing membership, including regular application and membership fee requirements.

End-use customers that have LMP-based contracts under which they have agreed to pay their LSE for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM may participate in the real time market as provided for under Real-time Operations below.

To participate in the program, the participant must also meet the metering requirements as described in the next section.

METERING REQUIREMENTS

Except for participants in the non-hourly metered customer pilot program, the Load Response Program end-use customers must have metering equipment that provides integrated hourly kWh values on an EDC account basis, for market settlement purposes, that either meets the EDC requirements for accuracy or has a maximum error of two percent over the full range of the meter (including potential transformers and current transformers). The installed meter must be one of the following:

EDC-owned hourly meter,

End-use customer-owned meter including one provided by an independent metering service provider or acquired from the CSP or LSE, approved by PJM, that is read electronically by PJM, or

End-use customer-owned meter including one provided by an independent metering service provider or acquired from the CSP or LSE, approved by PJM, that is read by the end-use customer (or the CSP/LSE), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Note that various Internet applications now exist for transmission of real time metered data. Use of these applications is acceptable provided that PJM receives metered load reductions in a timely, reliable manner.

The metering requirements can be met using either of the following methods:

Metering that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generators).

Metered load on an EDC account basis, comparing actual metered load to a Customer Baseline Load (CBL) calculated as described below.

CUSTOMER BASELINE LOAD (CBL)

For those program end-use customers that wish to measure load reductions by comparing metered load against an estimate of what metered load would have been absent the reduction, a CBL must be calculated. The CBL is calculated using the following methodologies:

The Average Day CBL

Average Day CBL formula for weekdays

Step 1. Establish the CBL Basis: A set of days that will serve as representative of end-use customers typical usage.

The Weekday ***CBL Basis Window*** is comprised of the 10 most recent days, beginning with the day two days prior to the event day for which the CBL is being calculated, excluding the following day-types

1. NERC holidays

2. Weekend days

3. Event days, which are defined as days on which:

PJM declared a curtailment event for which the end-use customer was eligible, or

the end-use customer actually reduced load and its measured reduction was submitted to PJM for compensation.

4. Any day which the days average daily event period usage is less than 75% of the average event period usage level.

To define the days that comprise the weekday CBL Basis Window:

Begin with the 10-day period defined by the weekday that is two days prior to the event through the weekday that is eleven days prior to the event day. This creates a 10-day window.

Eliminate any holidays, and replace them with days beginning with the 12th weekday day prior to the event day continuing until a non-holiday is encountered. This results in a 10-day window.

Eliminate any event days, replacing them with subsequent prior days, picking up with the first day not yet included in the window after completing the holiday replacement requirement.

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The final **weekday CBL Window** must contain 10 weekdays.

Step 2. Establish the CBL Basis. Identify the five days from the 10-day weekday CBL Basis Window to be used to develop CBL values for each hour of the event.

For each of the 10 days in the weekday CBL Basis Window, create the *average daily event period usage* for that day, which is defined as the simple average of the participants actual usage over the hours in the day that define the event for which the weekday CBL is being developed.

Create the *average event period usage level* for the 10 days in the weekday CBL Basis Window, which is defined as the simple average of the 10 average daily event period usage values.

Eliminate low usage days. For any day in the 10-day window for which the days average daily event period usage is less than 75% of the average event period usage level, eliminate that day, then repeat Step 1 and 2 to replace the eliminated days and to create a new 10-day weekday CBL Basis Window.

Order the 10 days in the weekday CBL Basis Window according to their average daily event period usage level, and eliminate the five days with the lowest average daily event period usage.

The remaining five days constitute the weekday **CBL Basis** .

For each hour of the event, the weekday CBL is the average of the usage in that hour in the five days that comprise the weekday CBL Basis.

Average Day CBL formula for weekends and NERC holidays

Step 1. Establish the CBL Weekend/Holiday Basis Window

The weekend/holiday CBL Basis Window is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for holidays or event days.

Step 2. Establish the Weekend/Holiday CBL Basis.

Calculate the average daily event period usage value for each of the three days in the weekend/holiday CBL Basis Window.

Order the three days according to their average daily event period usage level.

Eliminate the day with the lowest average value

The weekend/holiday CBL Basis contains 2 days.

Step 3. Calculate Weekend Average Day CBL values for the event.

For each hour of the event, the CBL value is the average of usage in that hour in the two days that comprise the weekend/holiday CBL Basis.

Significant Load Change Notification

The end-use customer shall inform PJM directly or inform its CSP/LSE, who shall inform PJM, of any significant change to the end-use customers operations that increases or decreases the end-use customers CBL. A significant incremental change is defined as any operational or physical change to the end-use customers facilities that will adjust more than half the hours in the end-use customers CBL by at least 20% for more than twenty consecutive days. PJM may require and approve such adjustments to the CBL as are necessary to reflect the significant incremental change.

Alternate Methods

PJM may consider a metering basis other than those described above if the method accurately represents an end-use customers normal load profile during the event. Suggestions for alternative methods by which load reductions may be measured may be approved by PJM for use in this program if negotiated in good faith and agreed to by all appropriate parties, including the EDC, LSE, the end-use customer, and CSP. PJM will consider such suggestions on a case-by-case basis and intends to study alternative measurement methods during the life of the program and report the results. Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the CSP and verified by PJM with the EDC.

W EATHER -S ENSITIVE A DJUSTMENT (WSA)

At the time it enters the Load Response Program, the end-use customer or its representative (LSE/CSP), shall specify whether it desires to apply the WSA for the summer period (May-October, inclusive) or the winter period (November-April) or both. The election to apply the WSA may be changed only annually.

The WSA shall increase or decrease the CBL. The WSA shall be calculated for interval-metered end-use customers as follows:

Regression Analysis (available for the summer and the winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customers on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index (THI) on a seasonal basis for the period the WSA is being applied.

PJM will post on the PJM website a spreadsheet of the THI values for all relevant weather stations located within PJM.

The regression analysis will produce a slope (m), expressed in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customers load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

WSA = [(m x THI $_{\text{EVENT DAY}}$) + b]/[(m x THI $_{\text{CBL DAYS}}$) + b]

Simplified Analysis (available for the summer period only)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the CSP, and the LSE or by PJM if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to PJM equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customers location may be used if it can be shown that the temperature at the end-use customers location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the load reduction event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5%. If the difference is greater than 5% then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to PJM documenting the weather adjustment.

The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.

For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100%. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4, above.

In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customers historical, seasonal, on-peak non-coincident peak load.

Case-by-case suggestions for alternative WSA methods or adjustments to the end-use customers historical, seasonal, on-peak non-coincident peak load may be approved by PJM for use in this Economic Load Response Program if negotiated in good faith and agreed to by all appropriate parties.

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IssuedOn:	September 3, 2004

REGISTRATION

End-use customers or their representatives (LSEs/CSPs) must complete the PJM Economic Load Response Program Registration Form that is posted on the PJM web site (www.pjm.com). The following general steps will be followed:

1. The end-use customer or its representative (LSE/CSP) completes the PJM Economic Load Response Program registration form located on the PJM web site. In the event an LSE or CSP completes the form, a separate registration form must be submitted for each end-use customer the LSE/CSP represents that actually can reduce load.

2. PJM reviews the application and ensures that the qualifications for participation in the program are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate EDC and LSE whether the load that might be reduced is under other contractual obligation. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract. PJM will verify the transmission and generation [1] charges with the appropriate EDC/LSE. The EDC and LSE have ten (10) business days to respond or PJM assumes acceptance.

3. PJM informs the end-use customer or its representative (LSE/CSP) of acceptance into the program and notifies the appropriate LSE and EDC of the participants acceptance into the program.

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Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

End-use customers may not be registered simultaneously in the Economic Load Response Program and the Emergency Load Response Program. End-use customers, however, may switch programs upon one-day notice if it has participated in the same load response program for 15 consecutive days.

REAL TIME OPERATIONS

The Economic Load Response Program is not based on the declaration of emergency conditions in PJM, but rather on the economic decisions of the PJM market participants. That is, the participants in the program are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise. The prime indicator of such conditions is assumed to be the LMP of energy on the PJM system.

[1] EDCs functioning as LSEs may use the average shopping credit for generation and transmission for a rate class.

In order to maintain adequate system control, PJM operators will be required to know the amount of load expected to be reduced at varying price levels. These amounts may change on a daily basis. An end-use customer or its representative (LSE/CSP) is therefore responsible for maintaining the load reduction information associated with the end-use customer signed up for the program, including the amount and the price at which load might be reduced. The Load Response Program Registration/Update web site shall be used for this purpose. PJM will utilize the data that has been submitted via this site to compile daily aggregate load reductions on a zonal basis for use in operations.

Except for end-use customers that have LMP-based contracts as described below, end-use customers participating in the Economic Load Response Program may choose to reduce load whenever their zonal LMP dictates that it is economically beneficial for them to do so or may choose to be dispatched by PJM. The end-use customer or its representative (LSE/CSP) shall send an email to PJM (address to be supplied upon registration) concurrent with or up to one hour immediately prior to beginning the reduction. In cases where the load response is dispatched by PJM, payment will not be less than the total value of the load response bid including any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Load reductions under this program will not be eligible to set real time price on the PJM system unless metered directly by PJM. End-use customers or their representatives (LSE/CSP) shall send an email to PJM (address to be supplied upon registration) concurrent with or up to one hour immediately prior to the end of their load reduction.

End-use customers that have LMP-based contracts pursuant to which they have agreed to pay their LSE for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, may choose to reduce load and be compensated for the reduction under the following circumstances. The end-use customer or its representative (LSE/CSP) shall provide PJM with a strike price for the end-use customers zonal LMP at which the end-use customer will reduce load, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the load reduction must be committed. In cases where the end-use customers zonal LMP reaches the strike price and the load response is dispatched by PJM, PJM shall pay such end-use customer the difference between the actual savings achieved based on zonal LMP and the total value of the end-use customers load response bid, if savings achieved by the end-use customer are less than the total value of the load response bid. For purposes of this provision the total value of the load response bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the reduction was dispatched by PJM or the minimum down-time whichever is greater, plus the submitted start-up costs. Load reductions hereunder will not be eligible to set real time price on the PJM system.

End-use customers or their representatives (LSEs/CSPs) shall send e-mails to PJM (address to be supplied upon registration) concurrent with or up to one hour immediately prior to, and at the end of, their load reductions.

VERIFICATION

For load reduction that is not metered directly by PJM (i.e. is collected by the EDC), data is to be submitted to PJM within 60 days of the event. If the data is not received within 60 days, no payment for participation is provided. Meter readings must be provided for each hour during which load reduction was accomplished.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. PJM will forward directly metered data to the appropriate EDC and LSE immediately following an event for optional review. PJM will forward CBL and WSA calculations to the appropriate EDC and LSE immediately following an event for optional review. Data files submitted after-the-fact will be forwarded to the EDC and LSE upon receipt. The LSE and/or EDC have ten (10) business days after receiving the data to provide feedback to PJM. All load reduction data is subject to audit by PJM.

PJM MARKET MONITORING

PJM may investigate participant behavior and claims under this program and may take actions as described under the PJM Market Monitoring Plan.

MARKET SETTLEMENTS

Reimbursement for reducing load is based on the actual kWh relief provided in excess of committed day-ahead load reductions plus the adjustment for losses. If the real time LMP is less than $75/MWh, the end-use customer (or its representative (LSE/CSP)) that curtails load in real-time will be paid by PJM the real time LMP less an amount equal to the applicable generation and transmission [2] charges. If the real time LMP is greater than or equal to $75/MWh, an end-use customer (or its representative (LSE/CSP)) that curtails load in real-time will be paid the real time LMP. In cases where the load response is dispatched by PJM, or the strike price of end-use customer with an LMP based contract is reached and such load response is dispatched by PJM, payment will not be less than the total value of the load response bid, including any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, real time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) LMP is used as appropriate for the individual end-use customer. The applicable generation and transmission [2] charge is the charge the end-use customer would have otherwise paid the LSE absent the load reduction.

An end-use customer or its representative (LSE/CSP) will accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customers CBL at the corresponding hourly rate. In the event the end-use customers hourly energy consumption is greater than the CBL, the end-use customer or its representative (LSE/CSP) will accumulate debits at the corresponding hourly rate for the amount the end-use customers hourly energy consumption is greater than the CBL. However, in no event will the end-use customers (or its representatives) credit be reduced below zero on a daily basis.

Payments under the Economic Load Response Program will be made by PJM to the end-use customer or its representative (LSE/CSP). In the event the CSP or LSE is the party to be paid but is not the load reducer, the portion of the payment that will be transferred from the LSE/CSP to the end-use customer that actually reduced load is outside the scope of this program, and must be arranged between the LSE/CSP and the end-use customer.

[2] EDCs functioning as LSEs may use the average shopping credit for generation and transmission for a rate class.

PJM shall recover LMP less an amount equal to applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced. The amount equal to the generation and transmission charges, if any, will be recovered from all load within the zone in which the load that was reduced is located. If the total amount of recoverable charges reflecting generation and transmission charges for the entire program exceeds $17.5 million in a year, thereafter participants will receive LMP less an amount equal to the applicable generation and transmission charges regardless of the level of LMP.

An ALM customer may participate in the Economic Load Response program during ALM events as long as the customers ALM contract explicitly excludes payment or credit for energy not consumed during ALM events. If the LSE that submitted the customer for ALM credit indicates that the customer is not eligible for simultaneous credit under the Economic Load Response program and ALM is called for concurrent with the Economic Load Response program, then payments will be made to the end-use customer or representative according to the Economic Load Response program only for the time during which ALM obligations were not in effect. Any response in excess of the contracted ALM amount will be compensated under the Economic Load Response program for the entire duration of response.

Program credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing*** .

REPORTING

PJM will submit any required reports to FERC on behalf of the Economic Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site. PJM shall submit two reports to the FERC with respect to the Economic Load Response Program. The first report shall be filed on May 31, 2003. The second report shall be filed on October 31, 2004, concurrently with PJMs report evaluating the PJM Emergency Load Response Program. These reports shall review and evaluate

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the Economic Load Response Program and shall include (1) evaluations of whether the current demand response programs are the best means for eliciting the maximum possible amount of demand response; (2) an evaluation of the Non-metered Customer Pilot Program, including whether the pilot program is the best means of obtaining participation by small customers; (3) examination of whether the level of compensation pursuant to the Economic Load Response Program is still necessary and appropriate to induce customers to join and remain in the Economic Load Response Program or, whether PJM could implement compensation programs that more closely respond to, and provide market signals; (4) an estimate of the costs and benefits of (a) implementing a compensation program with no incentive provision; (b) continuing the current incentive provision, or (c) enlarging the incentive provision; and (5) an evaluation of possible methods of obtaining significant amounts of demand response other than by providing financial incentives.

On an annual basis, PJM will prepare a report that summarizes the status of the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.

PJM will prepare any reports by state and by zone as may be required, subject to confidentiality requirements.

ECONOMIC LOAD RESPONSE PROGRAM - DAY - AHEAD

EFFECTIVE PERIOD OF PROGRAM

Same as real time.

PARTICIPANT QUALIFICATIONS

Same as real time except that end-use customers that have LMP-based contracts may not participate in the Day-ahead Market.

METERING REQUIREMENTS

Same as real time.

CUSTOMER BASELINE LOAD (CBL)

Same as real time.

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WEATHER-SENSITIVE ADJUSTMENT (WSA)

Same as real time except that the Simplified Analysis may not be used.

REGISTRATION

Same as real time.

DAY-AHEAD OPERATIONS

PJM will accept demand reduction bids from an end-use customer or its representative (LSE/CSP) for a specific MW curtailment (in minimum increments of .1 MW). The demand reduction bid will include the day-ahead LMP above which the end-use customer would not consume, and could also include start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and/or a minimum number of contiguous hours for which the load reduction must be committed.

The objective function for day ahead commitment software will be to eliminate demand reduction bids from day-ahead bid load when the total bid production cost over the 24-hour dispatch day will be reduced compared to serving that load, including consideration of paying the demand reduction bid for the length of the minimum commitment time as well as any start-up cost. Thus, curtailments will not be scheduled unless they reduce total day-ahead production costs.

Demand reduction bids can set day-ahead LMP just as a comparably bid generator.

VERIFICATION

Same as real time.

PJM MARKET MONITORING

Same as real time.

MARKET SETTLEMENTS

Reimbursement for reducing load is based on the reductions of kWh committed in the Day Ahead Market. An end-use customer or its representative (LSE/CSP) that submits a load reduction bid day ahead that is accepted by PJM when the day ahead LMP is less than $75 MWh will be paid by PJM the day ahead LMP less an amount equal to the applicable generation and transmission [3] charges. An end-use customer or its representative (LSE/CSP) that submits a load reduction bid day ahead that is accepted by PJM when the day ahead LMP is greater than or equal to $75 MWh, will be paid by PJM the day ahead LMP.

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Total payments to end-use customers or their representatives (LSEs/CSPs) for accepted day-ahead load response bids will not be less than the total value of the load response bid, including any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) LMP is used as appropriate for the individual end-use customer. The applicable generation and transmission [3] charge is the charge the participant would have otherwise paid the LSE absent the load reduction.

Payments under the Economic Load Response Program will be made by PJM to the end-use customer or its representative (LSE/CSP). In the event the CSP or LSE is the party to be paid but is not the load reducer, the portion of the payment that will be transferred from the LSE/CSP to the end-use customer that actually reduced load is outside the scope of this program, and must be arranged between the LSE/CSP and the end-use customer.

PJM shall recover LMP less an amount equal to applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced. The amount equal to the generation and transmission charges, if any, will be recovered from all load within the zone in which the load that reduced is located. If the total amount of recoverable charges reflecting the generation and transmission charges for the entire program exceeds $17.5 million in a year, thereafter participants will receive LMP less an amount equal to the applicable generation and transmission charges regardless of the level of LMP.

[3] EDCs functioning as LSEs may use the average shopping credit for generation and transmission for a rate class.

An ALM customer may participate in the Economic Load Response program during ALM events as long as the customers ALM contract explicitly excludes payment or credit for energy not consumed during ALM events. If the LSE that submitted the customer for ALM credit indicates that the customer is not eligible for simultaneous credit under the Economic Load Response program and ALM is called for concurrent with the Economic Load Response program, then payments will be made to the end-use customer or representative according to the Economic Load Response program only for the time during which ALM obligations were not in effect. Any response in excess of the contracted ALM amount will be compensated under the Economic Load Response program for the entire duration of response.

Program credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing*** .

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NON-PERFORMANCE

End-use customers or their representatives (LSEs/CSPs) that have load reductions committed in the day-ahead market that cannot demonstrate hourly performance in real time equal to at least that of the day-ahead commitment will be charged real time LMP for the amount of the shortfall, plus any associated day-ahead operating reserve credits. Any extra funds collected by PJM as a result of this charge will serve to reduce the overall day-ahead operating reserves charge for that hour.

REPORTING

Same as real time.

NON-HOURLY METERED CUSTOMER PILOT

PJM also will consider LSE/CSP sponsored pilots for customers without hourly metering for participation in a pilot program for up to two years per end-use customer or the end date of the applicable program, whichever comes first, provided the end-use customers or their representatives (LSEs/CSPs) propose an alternate method for measuring hourly load reductions. Proposed methods shall be reviewed with the affected LSE(s). Alternate measurement mechanisms will be approved by PJM on a case-by-case basis. Participation in the non-hourly metered customer pilot will be limited to 100 MW aggregate load reduction over the PJM region and the Economic Load Response Program and the Emergency Load Response Program, and with the sole exception of the requirement for hourly metering, will be subject to the same rules and procedures as the Emergency Load Response Program or Economic Load Response Program (real-time and day-ahead options), whichever is applicable. Following the two-year pilot period, each alternate method must be approved through the normal PJM stakeholder process in order to continue to be used.

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SCHEDULE 2

COMPONENTS OF COST

(a) Each Market Participant obligated to sell energy from operating capacity on the PJM Interchange Energy Market at cost-based rates shall include the following components or their equivalent in the determination of costs for operating capacity supplied to or from the PJM Region:

(1) Boilers

Firing-up cost;

No-load cost during period of operation;

Peak-prepared-for maintenance cost;

Incremental labor cost; and

Other incremental operating costs.

(2) Machines

Starting cost from cold to synchronized operation;

No-load cost during period of operation;

Incremental labor cost; and

Other incremental operating costs.

(b) Each Member obligated to sell energy on the PJM Interchange Energy Market at cost-based rates shall include the following components or their equivalent in the determination of costs for energy supplied to the PJM Region:

Incremental fuel cost;

Incremental maintenance cost;

Incremental labor cost; and

Other incremental operating costs.

(c) All fuel costs shall employ the marginal fuel price experienced by the Member.

(d) The PJM Board, upon consideration of the advice and recommendations of the Members Committee, shall from time to time define in detail the method of determining the costs entering into the said components, and the Members shall adhere to such definitions in the preparation of incremental costs used on the Interconnection.

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SCHEDULE 2 - EXHIBIT A

EXPLANATION OF THE TREATMENT OF THE COSTS OF

EMISSION ALLOWANCES

The cost of emission allowances is included in Other Incremental Operating Costs pursuant to Schedule 2. The replacement cost of emission allowances will be used to recover the cost of emission allowances consumed as a result of producing energy for the PJM Region.

Index

Consistent with definitions promulgated by the PJM Board upon consideration of the advice and recommendations of the Members Committee under Schedule 2, each Member subject to Schedule 2 will determine and provide to the Interconnection its replacement cost of emission allowances, such cost to be an amount not exceeding the market price index published by Cantor-Fitzgerald Environmental Brokerage Services (EBS), or a PJM Board approved index in the event that EBS should cease publication of such index. As with all other components of cost required for accounting under this Agreement, each Member subject to Schedule 2 will use the same replacement cost of emissions allowances, so determined, as it uses for coordinating operation of its generating facilities hereunder.

For each Member subject to Schedule 2, the cost of emissions allowances is included in the cost of energy supplied to or received from the PJM Region.

Payment

The Members subject to Schedule 2 waive the right of payment-in-kind for emission allowances for transactions wholly between the parties. Cash payments for emission allowances consumed in providing energy for the PJM Region shall be incorporated into and conducted pursuant to the billing procedures for energy prescribed by this Agreement.

Calculation of Emission Allowance Amount and Cost

Pursuant to the letter from the PJM Interconnection to FERC dated June 26, 1995, the calculation of an annual average for the cost of emission allowances, described below, is required due to the profile of the PJM physical system and PJM Energy Management software system. An average emission allowance cost based on a standard production cost study case will be used to calculate the average cost of emission allowances for each pool megawatt produced.

The Emission Allowances (Tons of SO_2) associated with a transaction will be calculated by multiplying the magnitude of a transaction (MWhr) by an Emissions per MWHr Factor (Tons of SO_2 per MWhr):

Emission Allowances	=	Transaction Magnitude	x	Emissions per MWhr
Used (TonsofS02)		(MWhr)		Factor (Tons of S02 per MWhr)

The Emissions per MWHr Factor will be calculated by dividing the forecast annual emissions from all Phase I units (Tons of SO_2) by the Forecast Annual Total PJM Energy Production (MWhr):

Emissions per MWhr Factor (Tons of SO_2 per MWhr)	= $\dfrac{\text{Forecast Annual Phase I Unit Emissions (Tons of } SO_2\text{)}}{\text{Forecast Annual Total PJM Energy Production (MWhr)}}$

Likewise, the cost (Dollars) of the Emission Allowances for a transaction will be calculated by multiplying the transaction magnitude (MWhr) by a Charge per MWhr Factor (Dollars per MWHr).

Cost of Emission Allowances Used	=	Transaction Magnitude	x	Charge per MWhr Factor
(Dollars)		(MWhr)		(Dollars per MWhr)

The Charge per MWhr Factor will be calculated by multiplying, for each Member subject to Schedule 2, its Forecast Annual Emissions (Tons of SO_2)by its respective Emissions Allowance Replacement Cost (Dollars per Ton of SO_2) to yield each the forecasted annual cost of emissions (Dollars). Then, the total of forecasted annual cost of emissions for each Member subject to Schedule 2 is divided by the Forecast Annual Total PJM Energy Production (MWhr) to determine the Charge per MWHr Factor (Dollars per MWHr).

Charge per MWhr Factor = S $\dfrac{(A \times B)}{C}$, where:

A = Members Forecasted Annual Emissions, (Tons of SO_2)

B = Emission Allowance Replacement Cost, (Dollars per Ton of SO_2, per company)

C = Forecast Annual PJM Energy Production, (MWhr)

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SCHEDULE 3

ALLOCATION OF THE COST AND EXPENSES

OF THE OFFICE OF THE INTERCONNECTION

(a) Each group of Affiliates, each group of Related Parties, and each Member that is not in such a group shall pay an annual membership fee, the proceeds of which shall be used to defray the costs and expenses of the LLC, including the Office of the Interconnection. The amount of the annual fee as of the Effective Date shall be $5,000. The annual membership fee shall be charged on a calendar year basis. In the year that a new membership commences, the annual membership fee may be reduced, at the election of the entity joining, by 1/12th for each full month that has passed prior to membership commencing. If the entity seeking to join elects to pay a prorated annual membership fee as provided here, it shall not be permitted to vote at meetings until the first day following the date that its entry as a new Member is announced at a Members Committee meeting, provided that if an entitys membership is terminated and it seeks to rejoin within twelve months, it will be subject to the full $5,000 annual membership fee. Annual membership fees shall not be refunded, in whole or in part, upon termination of membership.

(b) Each group of State Offices of Consumer Advocates from the same state or the District of Columbia and each State Consumer Advocate that nominates its representative to vote on the Members Committee but is not in such a group shall pay an annual fee, the proceeds of which shall be used to defray the costs and expenses of the LLC, including the Office of the Interconnection. The amount of the annual fee shall be $500. The annual membership fee shall be charged on a calendar year basis and shall not be subject to proration for memberships commencing during a calendar year.

(c) The amount of the annual fees provided for herein shall be adjusted from time to time by the PJM Board to keep pace with inflation.

(d) All remaining costs of the operation of the LLC and the Office of the Interconnection and the expenses, including, without limitation, the costs of any insurance and any claims not covered by insurance, associated therewith as provided in this Agreement shall be costs of PJM Interconnection, L.L.C. Administrative Services and shall be recovered as set forth in Schedule 9 to the PJM Tariff. Such costs may include costs associated with debt service, including the costs of funding reserve accounts or meeting coverage or similar requirements that financing covenants may necessitate.

(e) An entity accepted for membership in the LLC shall pay all costs and expenses associated with additions and modifications to its own metering, communication, computer, and other appropriate facilities and procedures needed to effect the inclusion of the entity in the operation of the Interconnection.

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SCHEDULE 4

STANDARD FORM OF AGREEMENT TO BECOME A MEMBER OF THE LLC

Any entity which wishes to become a Member of the LLC shall, pursuant to Section 11.6 of this Agreement, tender to the President an application, upon the acceptance of which it shall execute a supplement to this Agreement in the following form:

Additional Member Agreement

1. This Additional Member Agreement (the Supplemental Agreement), dated as of _, is entered into among _and the President of the LLC acting on behalf of its Members.

2. _has demonstrated that it meets all of the qualifications required of a Member to the Operating Agreement. If expansion of the PJM Region is required to integrate _s facilities, a copy of Attachment J from the PJM Tariff marked to show changes in the PJM Region boundaries is attached hereto. _agrees to pay for all required metering, telemetering and hardware and software appropriate for it to become a member.

3. _agrees to be bound by and accepts all the terms of the Operating Agreement as of the above date.

4. _hereby gives notice that the name and address of its initial representative to the Members Committee under the Operating Agreement shall be:

____

5. The President of the LLC is authorized under the Operating Agreement to execute this Supplemental Agreement on behalf of the Members.

6. The Operating Agreement is hereby amended to include _as a Member of the LLC thereto, effective as of _, _, the date the President of the LLC countersigned this Agreement.

IN WITNESS WHEREOF, _and the Members of the LLC have caused this Supplemental Agreement to be executed by their duly authorized representatives.

Members of the LLC
By:
Name:
Title: President
By:
Name:
Title:

SCHEDULE 5

PJM DISPUTE RESOLUTION PROCEDURES

1. DEFINITIONS

1.1 Alternate Dispute Resolution Committee.

Alternate Dispute Resolution Committee shall mean the Committee established pursuant to Section 5 of this Schedule.

1.2 MAAC Dispute Resolution Committee.

MAAC Dispute Resolution Committee shall mean the committee established by the Mid-Atlantic Area Council to administer its industry-specific mechanism for resolving certain types of wholesale electricity disputes.

1.3 Related PJM Agreements.

Related PJM Agreements shall mean this Agreement, the East Transmission Owners Agreement, and the Reliability Assurance Agreement, the West Transmission Owners Agreement, and the Reliability Assurance Agreement-West.

2. PURPOSES AND OBJECTIVES

2.1 Common and Uniform Procedures.

The PJM Dispute Resolution Procedures are intended to establish common and uniform procedures for resolving disputes arising under the Related PJM Agreements. To the extent any of the foregoing agreements or the PJM Tariff contain dispute resolution provisions expressly applicable to disputes arising thereunder, however, this Agreement shall not supplant such provisions, which shall apply according to their terms.

2.2 Interpretation.

To the extent permitted by applicable law, the PJM Dispute Resolution Procedures are to be interpreted to effectuate the objectives set forth in Section 2.1. To the extent permitted by these PJM Dispute Resolution Procedures, the Alternate Dispute Resolution Committee shall coordinate with the established dispute resolution committee of an Applicable Regional Reliability Council, where appropriate, in order to conserve administrative resources and to avoid duplication of dispute resolution staffing.

3. NEGOTIATION AND MEDIATION

3.1 When Required.

The parties to a dispute shall undertake good-faith negotiations to resolve any dispute as to a matter governed by one of the Related PJM Agreements. Each party to a dispute shall designate an executive with authority to resolve the matter in dispute to participate in such negotiations. Any dispute as to a matter governed by one of the Related PJM Agreements that has not been resolved through good-faith negotiation shall be subject to non-binding mediation prior to the initiation of arbitral, regulatory, judicial, or other dispute resolution proceedings as may be appropriate as provided by these PJM Dispute Resolution Procedures.

3.2 Procedures.

3.2.1 Initiation.

If a dispute that is subject to the mediation procedures specified herein has not been resolved through good-faith negotiation, a party to the dispute shall notify the Alternate Dispute Resolution Committee in writing of the existence and nature of the dispute prior to commencing any other form of proceeding for resolution of the dispute. The Alternate Dispute Resolution Committee shall have ten calendar days from the date it first receives notification of the existence of a dispute from any of the parties to the dispute in which to distribute to the parties a list of mediators.

3.2.2 Selection of Mediator.

The Chair of the Alternate Dispute Resolution Committee shall distribute to the parties by facsimile or other electronic means a list containing the names of seven mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as it shall deem appropriate to the dispute. The Chair of the Alternate Dispute Resolution Committee may draw from the lists of mediators maintained by the established dispute resolution committee of an Applicable Regional Reliability Council, as the Chair shall deem appropriate. The persons on the proposed list of mediators shall have no official, financial, or personal conflict of interest with respect to the issues in controversy, unless the interest is fully disclosed in writing to all participants in the mediation process and all such participants waive in writing any objection to the interest. The parties shall alternate in striking names from the list with the last name on the list becoming the mediator. The determination of which party shall have the first strike off the list shall be determined by lot. The parties shall have ten calendar days to complete the mediator selection process, unless the time is extended by mutual agreement.

3.2.3 Advisory Mediator.

If the Alternate Dispute Resolution Committee deems it appropriate, it shall distribute two lists, one containing the names of seven mediators with mediation experience, and one containing the names of seven mediators with technical or business experience in the electric power industry. In connection with circulating the foregoing lists, the Alternate Dispute Resolution Committee shall specify one of the lists as containing the proposed mediators, and the other as a list of proposed advisors to assist the mediator in resolving the dispute. The parties shall then utilize the alternative strike procedure set forth above until one name remains on each list, with the last named persons serving as the mediator and advisor.

3.2.4 Mediation Process.

The disputing parties shall attempt in good faith to resolve their dispute in accordance with procedures and a timetable established by the mediator. In furtherance of the mediation efforts, the mediator may:

(a) Require the parties to meet for face-to-face discussions, with or without the mediator;

(b) Act as an intermediary between the disputing parties;

(c) Require the disputing parties to submit written statements of issues and positions;

(d) If requested by the disputing parties at any time in the mediation process, provide a written recommendation on resolution of the dispute including, if requested, the assessment by the mediator of the merits of the principal positions being advanced by each of the disputing parties; and

(e) Adopt, when appropriate, the Center for Public Resources Model ADR Procedures for the Meditation of Business Disputes (as revised from time to time) to the extent such Procedures are not inconsistent with any rule, standard, or procedure adopted by the Alternate Dispute Resolution Committee or with any provision of this Agreement.

3.2.5 Mediators Assessment.

(a) If a resolution of the dispute is not reached by the thirtieth day after the appointment of the mediator or such later date as may be agreed to by the parties, if not previously requested to do so the mediator shall promptly provide the disputing parties with a written, confidential, non-binding recommendation on resolution of the dispute, including the assessment by the mediator of the merits of the principal positions being advanced by each of the disputing parties. The recommendation may incorporate or append, if and as the mediator may deem appropriate, any recommendations or any assessment of the positions of the parties by the advisor, if any. Upon request, the mediator shall provide any additional recommendations or assessments the mediator shall deem appropriate.

(b) At a time and place specified by the mediator after delivery of the foregoing recommendation, the disputing parties shall meet in a good faith attempt to resolve the dispute in light of the recommendation of the mediator. Each disputing party shall be represented at the meeting by a person with authority to settle the dispute, along with such other persons as each disputing party shall deem appropriate. If the disputing parties are unable to resolve the dispute at or in connection with this meeting, then: (i) any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate as provided in the PJM Dispute Resolution Procedures; and (ii) the recommendation of the mediator, and any statements made by any party in the mediation process, shall have no further force or effect, and shall not be admissible for any purpose, in any subsequent arbitral, administrative, judicial, or other proceeding.

3.3 Costs.

Except as specified in Section 4.13, the costs of the time, expenses, and other charges of the mediator and any advisor, and of the mediation process, shall be borne by the parties to the dispute, with each side in a mediated matter bearing one-half of such costs, and each party bearing its own costs and attorneys fees incurred in connection with the mediation.

4. ARBITRATION

4.1 When Required.

Any dispute as to a matter: (i) governed by one of the Related PJM Agreements that has not been resolved through the mediation procedures specified herein, (ii) involving a claim that one or more of the parties owes or is owed a sum of money, and (iii) the amount in controversy is less than $1,000,000.00, shall be subject to binding arbitration in accordance with the procedures specified herein. If the parties so agree, any other disputes as to a matter governed by a Related PJM Agreement may be submitted to binding arbitration in accordance with the procedures specified herein.

4.2 Binding Decision.

Except as specified in Section 4.1, the resolution by arbitration of any dispute under this Agreement shall not be binding.

4.3 Initiation.

A party or parties to a dispute which is subject to the arbitration procedures specified herein shall send a written demand for arbitration to the Chair of the Alternate Dispute Resolution Committee with a copy to the other party or parties to the dispute. The demand for arbitration shall state each claim for which arbitration is being demanded, the relief being sought, a brief summary of the grounds for such relief and the basis for the claim, and shall identify all other parties to the dispute.

4.4 Selection of Arbitrator(s).

The parties to a dispute for which arbitration has been demanded may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of arbitrators prepared for the dispute by the Alternate Dispute Resolution Committee and delivered to the parties by facsimile or other electronic means promptly after receipt by the Alternate Dispute Resolution Committee of a demand for arbitration. The Alternate Dispute Resolution Committee may draw from the lists of arbitrators maintained by the established dispute resolution committee of an Applicable Regional Reliability Council, as the Alternate Dispute Resolution Committee deems appropriate. If the parties are unable to agree on a single arbitrator by the fourteenth day following delivery of the foregoing list of arbitrators or such other date as agreed to by the parties, then not later than the end of the seventh business day thereafter the party or parties demanding arbitration on the one hand, and the party or parties responding to the demand for arbitration on the other, shall each designate an arbitrator from a list for the dispute prepared by the Alternate Dispute Resolution Committee. The arbitrators so chosen shall then choose a third arbitrator.

4.5 Procedures.

The Alternate Dispute Resolution Committee shall compile and make available to the arbitrator(s) and the parties standard procedures for the arbitration of disputes, which procedures (i) shall include provision, upon good cause shown, for intervention or other participation in the proceeding by any party whose interests may be affected by its outcome, (ii) shall conform to the requirements specified in these PJM Dispute Resolution Procedures, and (iii) may be modified or adopted for use in a particular proceeding as the arbitrator(s) deem appropriate. To the extent deemed appropriate by the Alternate Dispute Resolution Committee, the procedures adopted by the Alternate Dispute Resolution Committee shall be based on the American Arbitration Association Rules, to the extent such Rules are not inconsistent with any rule, standard or procedure adopted by the Alternate Dispute Resolution Committee, or with any provision of these PJM Dispute Resolution Procedures. Upon selection of the arbitrator(s), arbitration shall go forward in accordance with applicable procedures.

4.6 Summary Disposition and Interim Measures.

4.6.1 Lack of Good Faith Basis.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator(s) does not have a good faith basis in either law or fact. If the arbitrator(s) determine(s) that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator(s) shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator(s) to the prevailing party.

4.6.2 Discovery Limits.

The procedures for the arbitration of a dispute shall provide a means for summary disposition without discovery of facts if there is no dispute as to any material fact, or with such limited discovery as the arbitrator(s) shall determine is reasonably likely to lead to the prompt resolution of any disputed issue of material fact.

4.6.3 Interim Decision.

The procedures for the arbitration of a dispute shall permit any party to a dispute to request the arbitrator(s) to render a written interim decision requiring that any action or decision that is the subject of a dispute not be put into effect, or imposing such other interim measures as the arbitrator(s) deem necessary or appropriate, to preserve the rights and obligations secured by any of the Related PJM Agreements during the pendency of the arbitration proceeding. The parties shall be bound by such written decision pending the outcome of the arbitration proceeding.

4.7 Discovery of Facts.

4.7.1 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, and (iii) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified by the procedures established by the Alternate Dispute Resolution Committee, the arbitrator(s) or agreement of the parties.

4.7.2 Procedures Arbitrator.

The sole arbitrator, or the arbitrator selected by the arbitrators chosen by the parties, as the case may be (such arbitrator being hereafter referred to as the Procedures Arbitrator), shall be responsible for establishing the timing, amount, and means of discovery, and for resolving discovery and other pre-hearing disagreement. If a dispute involves contested issues of fact, promptly after the selection of the arbitrator(s) the Procedures Arbitrator shall convene a meeting of the parties for the purpose of establishing a schedule and plan of discovery and other pre-hearing actions.

4.8 Evidentiary Hearing.

The procedures for the arbitration of a dispute shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be as described in the Federal Rules of Evidence, except as modified by the procedures established by the Alternate Dispute Resolution Committee, the arbitrator(s) or agreement of the parties. The arbitrator(s) may require such written or other submissions from the parties as shall be deemed appropriate, including submission of the direct testimony of witnesses in written form. The arbitrator(s) may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. Any party or parties may arrange for the preparation of a record of the hearing, and shall pay the costs thereof. Such party or parties shall have no obligation to provide or agree to the provision of a copy of the record of the hearing to any party that does not pay an equal share of the cost of the record. At the request of any party, the arbitrator(s) shall determine a fair and equitable allocation of the costs of the preparation of a record between or among the parties to the proceeding willing to share such costs.

4.9 Confidentiality.

4.9.1 Designation.

Any document or other information obtained in the course of an arbitral proceeding and not otherwise available to the receiving party, including any such information contained in documents or other means of recording information created during the course of the proceeding, may be designated Confidential by the producing party. The party producing documents or other information marked Confidential shall have twenty days from the production of such material to submit a request to the Procedures Arbitrator to establish such requirements for the protection of such documents or other information designated as Confidential as may be reasonable and necessary to protect the confidentiality and commercial value of such information and the rights of the parties, which requirements shall be binding on all parties to the dispute. Prior to the decision of the Procedures Arbitrator on a request for confidential treatment, documents or other information designated as Confidential shall not be used by the receiving party or parties, or the arbitrator(s), or anyone working for or on behalf of any of the foregoing, for any purpose other than the arbitration proceeding, and shall not be disclosed in any form to any person not involved in the arbitration proceeding without the prior written consent of the party producing the information or as permitted by the Procedures Arbitrator.

4.9.2 Compulsory Disclosure.

Any party receiving a request or demand for disclosure, whether by compulsory process, discovery request, or otherwise, of documents or information obtained in the course of an arbitration proceeding that have been designated Confidential and that are subject to a non-disclosure requirement under these PJM Dispute Resolution Procedures or a decision of the Procedures Arbitrator, shall immediately inform the party from which the information was obtained, and shall take all reasonable steps, short of incurring sanctions or other penalties, to afford the person or entity from which the information was obtained an opportunity to protect the information from disclosure. Any party disclosing information in violation of these PJM Dispute Resolution Procedures or requirements established by the Procedures Arbitrator shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

4.9.3 Public Information.

Nothing in the Related PJM Agreements shall preclude the use of documents or information properly obtained outside of an arbitral proceeding, or otherwise public, for any legitimate purpose, notwithstanding that the information was also obtained in the course of the arbitral proceeding.

4.10 Timetable.

Promptly after the selection of the arbitrator(s), the arbitrator(s) shall set a date for the issuance of the arbitral decision, which shall be not later than eight months (or such earlier date as may be agreed to by the parties to the dispute) from the date of the selection of the arbitrator(s), with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the evidentiary hearing or other final submission of evidence shall not be changed absent extraordinary circumstances. The arbitrator(s) shall have the power to impose sanctions, including dismissal of the proceeding for dilatory tactics or undue delay in completing the arbitral proceedings.

4.11 Advisory Interpretations.

Except as to matters subject to decision in the arbitration proceeding, the arbitrator(s) may request as may be appropriate from any committee or subcommittee established under a Related PJM Agreement or by the Office of the Interconnection, an interpretation of any Related PJM Agreements, or of any standard, requirement, procedure, tariff, Schedule, principle, plan or other criterion or policy established by any committee or subcommittee. Except to the extent that the Office of the Interconnection is itself a party to a dispute, the arbitrator(s) may request the advice of the Office of the Interconnection with respect to any matter relating to a responsibility of the Office of the Interconnection under the Agreement or with respect to any of the Related PJM Agreements, or to the PJM Manuals. Any such interpretation or advice shall not relieve the arbitrator(s) of responsibility for resolving the dispute or deciding the arbitration proceeding in accordance with the standards specified herein.

4.12 Decisions.

The arbitrator(s) shall issue a written decision, including findings of fact and the legal basis for the decision. The arbitral decision shall be based on (i) the evidence in the record, (ii) the terms of the Related PJM Agreements, as applicable, (iii) applicable United States federal and state law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) relevant decisions in previous arbitration proceedings. The arbitrator(s) shall have no authority to revise or alter any provision of the Related PJM Agreements. Any arbitral decision issued pursuant to these PJM Dispute Resolution Procedures that affects matters subject to the jurisdiction of FERC under Section 205 of the Federal Power Act shall be filed with FERC.

4.13 Costs.

Unless the arbitrator(s) shall decide otherwise, the costs of the time, expenses, and other charges of the arbitrator(s) shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitral proceeding shall bear its own costs and fees. The arbitrator(s) may award all or a portion of the costs of the time, expenses, and other charges of the arbitrator(s), the costs of arbitration, attorneys fees, and the costs of mediation, if any, to any party that substantially prevails on an issue determined by the arbitrator(s) to have been raised without a substantial basis.

4.14 Enforcement.

If the decision of the arbitrator(s) is binding, the judgment may be entered on such arbitral award by any court having jurisdiction thereof; provided, however, that within one year of the issuance of the arbitral decision any party affected thereby may request FERC or any other federal, state, regulatory or judicial authority having jurisdiction to vacate, modify, or take such other action as may be appropriate with respect to any arbitral decision that is based upon an error of law, or is contrary to the statutes, rules, or regulations administered or applied by such authority. Any party making or responding to, or intervening in proceedings resulting from, any such request, shall request the authority to adopt the resolution, if not clearly erroneous, of any issue of fact expressly or necessarily decided in the arbitral proceeding, whether or not the party participated in the arbitral proceeding.

5. ALTERNATE DISPUTE RESOLUTION COMMITTEE

5.1 Membership.

5.1.1 Representatives.

The Alternate Dispute Resolution Committee shall be composed of two representatives selected by each of the following: (i) the Office of the Interconnection; (ii) the Members Committee; and one representative selected by each of the following: (i) the parties to the Reliability Assurance Agreement; (ii) the parties to the Reliability Assurance Agreement-West; (iii) the parties to the West Transmission Owners Agreement; and (iv) the parties to the East Transmission Owners Agreement.

5.1.2 Term.

Representatives on the Alternate Dispute Resolution Committee shall serve for terms of three years and may serve additional terms.

5.2 Voting Requirements.

Approval or adoption of measures by the Alternate Dispute Resolution Committee shall require two-thirds of the votes of the representatives present and voting. Two-thirds of the representatives on the Alternate Dispute Resolution Committee shall constitute a quorum for the conduct of business.

5.3 Officers.

At the first meeting of the Alternate Dispute Resolution Committee, the representatives to the Alternate Dispute Resolution Committee shall choose a Chair and Vice Chair from among the representatives on the Committee. The Chair of the Alternate Dispute Resolution Committee shall preside at meetings of the Committee, and shall have the power to call meetings of the Committee and to exercise such other powers as are specified in this Agreement or are authorized by the Alternate Dispute Resolution Committee. The Vice Chair shall preside at meetings of the Alternate Dispute Resolution Committee in the absence of the Chair, and shall exercise such other powers as are delegated by the Chair.

5.4 Meetings.

The Alternate Dispute Resolution Committee shall meet at such times and places as determined by the Committee, or at the call of the Chair. The Chair shall call a meeting of the Alternate Dispute Resolution Committee upon the request of two or more representatives on the Alternate Dispute Resolution Committee.

5.5 Responsibilities.

The duties of the Alternate Dispute Resolution Committee include but are not limited to the following:

i) Maintain a list of persons qualified by temperament and experience, and with technical or legal expertise in matters likely to be the subject of disputes, to serve as mediators or arbitrators under these PJM Dispute Resolution Procedures;

ii) Determine the rates and other costs and charges that shall be paid to mediators, advisors and arbitrators for or in connection with their services;

iii) Determine whether mediation is not warranted in a particular dispute;

iv) Provide to disputing parties lists of mediators, advisors or arbitrators to resolve particular disputes;

Compile and make available to parties to disputes, arbitrators, and other interested persons suggested procedures for the arbitration of disputes in accordance with Section 4.5;

Maintain and make available to parties to disputes, mediators, advisors, arbitrators, and other interested persons the written decisions required by Section 4.12;

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vi) Establish such procedures and schedules, in addition to those specified herein, as it shall deem appropriate to further the prompt, efficient, fair and equitable resolution of disputes; and

vii) Provide such oversight and supervision of the dispute resolution processes and procedures instituted pursuant to the Related PJM Agreements as may be appropriate to facilitate the prompt, efficient, fair and equitable resolution of disputes.

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SCHEDULE 6

REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

1.1 Purpose and Objectives.

This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the Office of the Interconnection to prepare a plan for the enhancement and expansion of the Transmission Facilities in order to meet the demands for firm transmission service, and to support competition, in the PJM Region. The Regional Transmission Expansion Plan to be developed shall enable the transmission needs in the PJM Region to be met on a reliable, economic and environmentally acceptable basis.

1.2 Conformity with NERC and Other Applicable Criteria.

(a) NERC establishes Planning Principles and Guides to promote the reliability and adequacy of the North American bulk power supply as related to the operation and planning of electric systems.

(b) MAAC is responsible for ensuring the adequacy, reliability and security of the bulk electric supply systems in the MAAC region through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Planning Principles and Guides and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System of the MAAC Group.

(c) ECAR is responsible for ensuring the adequacy, reliability and security of the bulk electric supply systems in the ECAR region through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Planning Principles and Guides and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System of the ECAR Group.

(c.01) MAIN is responsible for ensuring the adequacy, reliability and security of the bulk electric supply systems in the MAIN region through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Planning Principles and Guides and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System for MAIN.

(d) The Regional Transmission Expansion Plan shall conform with the applicable reliability principles, guidelines and standards of NERC, MAAC, MAIN, ECAR, and other Applicable Regional Reliability Councils in accordance with the operating criteria and other procedures detailed in the PJM Manuals.

1.3 Establishment of Committees.

(a) The Planning Committee shall be open to participation by all stakeholders and shall provide technical advice and assistance to the Office of the Interconnection in all aspects of its regional planning functions. The Transmission Owners shall supply representatives to the Planning Committee to provide the data, information, and support necessary for the Office of the Interconnection to perform studies as required and to develop the Regional Transmission Expansion Plan. Other Members may provide representatives to the Planning Committee as they deem appropriate.

(b) The Transmission Expansion Advisory Committee established by the Office of the Interconnection will meet periodically with representatives of the Office of the Interconnection to provide advice and recommendations to the Office of the Interconnection to aid in the development of the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee will invite participation by: (i) all Transmission Customers, as that term is defined in the PJM Tariff, and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the agencies and offices of consumer advocates of the States in the PJM Region exercising regulatory authority over the rates, terms or conditions of electric service or the planning, siting, construction or operation of electric facilities and (v) any other interested entities or persons.

1.4 Contents of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner and of supporting competition in the PJM Region.

(b) The Regional Transmission Expansion Plan shall reflect transmission enhancements and expansions, load and capacity forecasts and generation additions and retirements for the ensuing ten years.

(c) The Regional Transmission Expansion Plan shall, as a minimum, include a designation of the Transmission Owner or Owners or other entity that will construct, own and/or finance each transmission enhancement and expansion and how all reasonably incurred costs are to be recovered.

(d) The Regional Transmission Expansion Plan shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities; (iii) take into account the legal and contractual rights and obligations of the Transmission Owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM Region; (v) strive to maintain and, when appropriate, to enhance the economic and operational efficiency of wholesale electric service markets in the PJM region; and (vi) provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the transmission system or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnections in its on-going evaluation of the transmission systems economic and operational adequacy and performance; (iii) required as a result of the Office of the Interconnections assessment of the transmission systems compliance with MAAC, MAIN or ECAR reliability criteria, more stringent reliability criteria, if any; or PJM operating criteria; (iv) constraints or available transfer capability shortage are identified by the Office of the Interconnection as a result of generation additions or retirements, evaluation of load forecasts, congestion events on or operational performance of the transmission system, or proposals for the addition of Transmission Facilities in the PJM region; or (v) expansion of the transmission system is proposed by one or more Transmission Owners or by a Transmission Interconnection Customer.

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee of the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee shall notify the Office of the Interconnection in writing of any additional transmission considerations to be included.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee to prepare the studys scope, assumptions and procedures.

1.5.3 Scope of Studies.

In general, enhancement and expansion studies shall include:

(a) An identification of existing and projected limitations on the transmission systems physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.

(b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.

(c) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition in the PJM region.

(d) Engineering studies needed to determine the effectiveness and compliance (with reliability and operating criteria) of recommended enhancements and expansions.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual basis a 10-year forecast of summer and winter load and resources expected to be served by, or use, their Transmission Facilities. The forecast shall include to the extent known or reasonably capable of forecast: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); and (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owners transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons. The data required under this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies and consumer advocates of the States in the PJM Region, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in coordination with the transmission systems of the surrounding regional reliability councils and with the local transmission providers.

(b) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

(a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies on which the plan is based.

(b) Upon completion of its studies and analysis, the Office of the Interconnection shall prepare a recommended enhancement and expansion plan for review by the Transmission Expansion Advisory Committee. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection.

(c) The recommended plan shall separately identify enhancements and expansions for the MAAC Control Zone and for the PJM West Region.

(d) The recommended plan shall identify enhancements and expansions that are required to alleviate congestion on the Transmission System which, in the judgment of the Office of the Interconnection, cannot be hedged by the use of Financial Transmission Rights (FTRs) or other hedging opportunities available in PJM markets; that otherwise have not been proposed by any Transmission Owner or other entity; and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures and analyses described in Section 1.5.7 below.

(e) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to Section 1.1, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of Part IV of the PJM Tariff; (2) the proposed enhancement or expansion is consistent with applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by Part IV of the PJM Tariff with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(f) For each enhancement or expansion that is included in the recommended plan, the plan shall designate, based on the planning analysis; other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, the provisions of this Schedule 6 and/or those of Part IV of the PJM Tariff, one or more Transmission Owners or other entities to construct, own and/or finance the recommended transmission enhancement or expansion. To the extent that one or more Transmission Owners are designated to construct, own and/or finance a recommended transmission enhancement or expansion, the recommended plan shall designate the Transmission Owner that owns transmission facilities located in the Zone where the particular enhancement or expansion is to be located. Otherwise, any designation under this paragraph of more than one entity to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of proportional responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(g) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff, or (2) in the event and to the extent that no provision of the PJM Tariff assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through charges established pursuant to Schedule 12 of the Tariff. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnections assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in any amendment to Schedule 12 of the PJM Tariff that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under Sections 1.5.6(d) and 1.5.7 of this Schedule 6. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(h) Any Transmission Owner and other participants on the Transmission Expansion Advisory Committee may offer an alternative.

(i) If the Office of the Interconnection adopts the alternative, based upon its review of the relative costs and benefits, the ability of the alternative to supply the required level of transmission service, and its impact on the reliability of the Transmission Facilities, the Office of the Interconnection shall make any necessary changes to the recommended plan.

(j) If, based upon its review of the relative costs and benefits, the ability of the alternative to supply the required level of transmission service, and the alternatives impact on the reliability of the Transmission Facilities, the Office of the Interconnection does not adopt such alternative, the Transmission Owner or Owners whose alternative or alternatives have not been accepted or to whom cost responsibility has been assigned and other participants on the Transmission Expansion Advisory Committee may require that its or their alternative(s) be submitted to Alternative Dispute Resolution.

1.5.7 Development of Economic Transmission Enhancements and Expansions.

(a) The objective of the economic planning component of the regional transmission planning protocol is to provide cost-effective transmission solutions to alleviate congestion on the Transmission System which, in the judgment of the Office of the Interconnection, cannot be hedged by the use of FTRs or other hedging instruments available pursuant to the PJM Tariff or the Operating Agreement and that no market participant or other entity otherwise has proposed to resolve. Commencing with the regional planning cycle beginning on August 1, 2003, the Office of the Interconnection shall employ the procedures and analyses generally described in this section to assess the need for, and, where appropriate, to develop, such economic transmission enhancements and expansions. To the extent not stated in this section, the Office of the Interconnection shall publish in the PJM Manuals the specific factors and calculations used in the analysis.

(b) The Office of the Interconnection will continuously monitor congestion on the Transmission System and will calculate the hourly gross congestion cost associated with each transmission constraint on the system for the duration of each constraint. The hourly gross congestion cost for each individual constraint will be based on the shadow price associated with

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the constraint during each hour, as determined in the course of calculating the Locational Marginal Price. The total load affected by a constraint (total affected load) shall equal the sum of the loads at each bus on the Transmission System subject to the constraint multiplied by the appropriate powerflow distribution factor, excluding load at each bus that has a distribution factor less than 3% relative to the constraint. The hourly gross congestion cost per constraint shall be the product of (1) the applicable shadow price for such hour multiplied by (2) the total affected load (in MW) during the hour, (3) multiplied by the appropriate powerflow distribution factor. Total gross congestion cost of the constraint shall be the sum of the gross congestion cost of the constraint in all hours of the constraints duration. Total gross congestion cost of each constraint shall be accumulated over each occurrence of the constraint. The Office of the Interconnection shall post on the PJM Internet site the shadow price of each constraint during each hour and its calculations of the hourly and cumulative monthly total gross congestion cost of each constraint. Publication of such data shall not be affected by the commencement of either calculations of unhedgeable congestion under paragraph (c) below or a cost-benefit analysis under paragraph (d) below.

(c)(1) The Initial Thresholds for cumulative monthly total gross congestion costs for transmission constraints shall be:

Operating Voltage Of Constrained Facility	**Initial Threshold (gross congestion $)**	
greater than 345 kV	$	2,000,000/month
100 kV, up to and including 345 kV	$	250,000/month
less than 100 kV	$	100,000/month

(2) (A) On each occasion when the cumulative monthly total gross congestion cost of a constraint exceeds the applicable Initial Threshold, the Office of the Interconnection shall post a notice to that effect on the PJM Internet site and shall begin determining the extent to which the total affected load cannot be hedged by the use of FTRs or other measures, i.e., the extent of unhedgeable congestion associated with the applicable transmission constraint. The Office of the Interconnection shall calculate unhedgeable congestion on an hourly basis for each constraint.

(B) The hourly unhedgeable congestion cost per constraint shall be the product of (1) the applicable shadow price for such hour multiplied by (2) the total affected load (in MW) during the hour, less the sum (in MW) of (a) the annual FTRs that were allocated to the total affected load as ARRs in the most recent annual ARR allocation under the PJM Tariff; (b) any additional FTRs that could have been available to the total affected load as ARRs in the most recent annual ARR allocation, but which were not requested; (c) other long-term FTRs available to the total affected load as ARRs or FTRs from third parties, including Merchant Transmission Providers; and (d) economic local generation; multiplied by (3) the appropriate powerflow distribution factor.

(C) For purposes of the calculations of unhedgeable congestion and the calculations of net system benefits of potential solutions to such congestion under paragraph (d)(4) below, the following definitions shall apply:

(i) Economic local generation shall mean the amount of generation capacity (in MW) (other than units that are running out of merit order at an offer-capped price pursuant to Section 6 of Schedule 1 of the

Operating Agreement) that is on-line and available to affected load at each bus subject to the constraint, excluding generation at each bus that has a powerflow distribution factor on the constraint of less than 3%, at prices (as determined from generators day-ahead price bids into the PJM Energy Market, provided that a price bid of zero shall be attributed to self-scheduled units) no greater than the PJM system marginal price.

(ii) PJM system marginal price shall mean the systemwide unconstrained price of energy (system cost to meet load, assuming no transmission constraints), as determined in the calculation of Locational Marginal Price.

(iii) Powerflow distribution factor shall mean the percentage of power injected at a bus that flows on the constrained transmission facility relative to a system reference bus located outside the affected load area.

(3) Total unhedgeable congestion associated with a constraint shall be the sum of the unhedgeable congestion associated with the constraint in all hours of the constraints duration. Total unhedgeable congestion for each constraint shall be accumulated over each occurrence of the constraint.

(4) The Office of the Interconnection shall determine the extent to which unhedgeable congestion is attributable to recurring or non-recurring causes of transmission constraints. Recurring causes shall include, but shall not necessarily be limited to, periodic maintenance outages of transmission or generation facilities, forced outages of generation facilities, and forecasted, continuing increases in load. Non-recurring causes shall include, but shall not necessarily be limited to, forced outages of transmission facilities and outages for construction of new transmission (including interconnection) facilities.

(5) The Office of the Interconnection shall post on the PJM Internet site its calculations of the hourly and cumulative monthly unhedgeable congestion associated with each constraint for which it undertakes such calculations, as well as the portions of unhedgeable congestion that it attributes to recurring and non-recurring causes of transmission constraints. Publication of such information shall not be affected by the commencement of a cost-benefit analysis pursuant to paragraph (d) below.

(6) In the event that a constraint for which gross congestion costs exceeded the applicable Initial Threshold does not, within four months after it exceeds that threshold, present sufficient unhedgeable congestion to exceed the applicable Market Threshold under paragraph (d) below, the Office of the Interconnection may cease calculating unhedgeable congestion associated with the constraint until such time as the gross congestion cost associated with it again exceeds the applicable Initial Threshold. Notwithstanding the preceding sentence, however, the Office of the Interconnection at any time may calculate and consider in appropriate cost-benefit analyses unhedgeable congestion associated with a constraint for purposes of developing, pursuant to the last sentence of paragraph (d)(3) below, an economic transmission enhancement or expansion to resolve multiple constraints and/or to serve other, additional purposes.

(d)(1) The Market Thresholds for unhedgeable congestion associated with transmission constraints shall be:

Operating Voltage Of Constrained Facility	**Market Threshold (unhedgeablecongestion$)**	
greater than 345 kV	$	100,000/month
100 kV up to and including 345 kV	$	50,000/month
less than 100 kV	$	25,000/month

(2) On each occasion when the cumulative monthly unhedgeable congestion associated with a constraint exceeds the applicable Market Threshold, the Office of the Interconnection shall post on the PJM Internet site a notice advising that it shall immediately commence an initial cost-benefit analysis of potential transmission enhancements or expansions that would relieve the applicable transmission constraint. The Office of the Interconnection shall publish the results of the initial cost-benefit analysis as soon as completed, which shall be no later than 60 days after the date of the notice of commencement. Such initial cost-benefit results shall include (A) identification of the first transmission limit that caused the congestion that exceeded the applicable Market Threshold; (B) an estimate of the cost of eliminating the limit; (C) the estimated cost-benefit ratio of eliminating the limit and the Office of the Interconnections preliminary judgment of the relative likelihood that a transmission upgrade would cost-effectively resolve the unhedgeable congestion; (D) identification of any system upgrades already included in the Regional Transmission Expansion Plan that, in the Office of the Interconnections judgment, would mitigate the congestion; (E) preliminary identification of the market participants that would be the beneficiaries of, and therefore likely would be designated to bear responsibility for the costs or for payment of charges for recovery of the costs of, any economic transmission enhancement(s) or expansion(s) needed to remedy the congestion; and (F) a preliminary allocation of such costs among such market participants. At the earliest practical date after opening the Market Window (as defined in paragraph (d)(3) below), the Office of the Interconnection shall supplement the posting on the PJM Internet site pursuant to this paragraph (d)(2) to identify any additional transmission limits that contributed to the congestion event for which the Market Window has been opened and to provide an estimate of the cost of removing or mitigating each such additional limit. This supplemental information shall be of the same nature and scope as the information provided in the initial posting pursuant to this paragraph.

(3) Unless a market-based solution to the associated unhedgeable congestion is proposed within one year from the date of publication of the results of the initial cost-benefit analysis under paragraph (d)(2) above (hereafter, the Market Window), the Office of the Interconnection will propose to include in the Regional Transmission Expansion Plan the transmission enhancement or expansion that, in its judgment, is the most cost-effective, feasible transmission solution for the constraint associated with the unhedgeable congestion. When appropriate in its judgment, the Office of the Interconnection may propose an enhancement or expansion that will resolve multiple constraints and/or that will serve other, additional purposes, so long as it determines that the portion of such enhancement or expansion that is attributable to resolving the constraint(s) associated with the pertinent unhedgeable congestion is a cost-effective solution to such constraint(s).

(4)(A) The Office of the Interconnection shall commence a cost-benefit analysis under this paragraph (d)(4) upon opening a Market Window. Such analysis shall be ongoing in nature and shall continue without regard to the results of the initial cost-benefit assessment under paragraph (d)(2) above. The ongoing analysis shall take into account all cumulative unhedgeable congestion, including unhedgeable congestion experienced during the Market Window; the Office of the Interconnections projections of likely future unhedgeable congestion arising from recurring causes of the applicable transmission constraint (as described in paragraph (c)(4) above); the estimated costs of transmission enhancements and expansions that, in the Office of the Interconnections judgment, may cost-effectively mitigate or eliminate the transmission constraint associated with the relevant unhedgeable congestion; any transmission enhancements or upgrades that will remedy multiple, related congestion events; anticipated load growth that may affect the relevant congestion; and the effects of future upgrades included in the Regional Transmission Expansion Plan. The analysis shall also take into account the portion of unhedgeable congestion that may not be eliminated by the transmission enhancements or expansions. In the event that an upgrade included in, or which, during the Market Window, is added to, the Regional Transmission Expansion Plan for purposes of maintaining reliability of service would fully resolve the relevant unhedgeable congestion, the Office of the Interconnection shall limit the cost-benefit analysis to assessing the cost-effectiveness of accelerating construction of the pertinent upgrade or, in the event that the magnitude of the congestion realized and expected to be experienced prior to construction of the upgrade indicates that acceleration is unnecessary or unjustified, shall suspend the cost-benefit analysis pending construction of such upgrade.

(B) The benefits of a potential transmission upgrade shall be the estimated net system benefit of the facility over a period of ten years from the projected date of the upgrades commissioning for service. The net system benefit shall equal (1) the value of the unhedgeable congestion that the upgrade would relieve, determined as described below, less (2) the sum of (a) costs associated with any increase in energy prices outside the constrained area that is anticipated to arise from removal of the constraint, (b) the estimated value of any increase or decrease in congestion on other facilities after removal of the constraint, and (c) the costs of any congestion anticipated to arise due to outages required to construct the upgrade. Factor (1) in the calculation of net system benefit shall be projected based on hourly calculations of congestion experienced during the Market Window and shall equal the product of (i) the applicable shadow price multiplied by (ii) the total affected load (in MW), less the sum (in MW) of (x) all annual FTRs available or projected to be available to the affected load (including those allocated and those available, but not requested, in the annual ARR allocation under the PJM Tariff and those available as ARRs or FTRs from third parties, including Merchant Transmission Providers); and (y) economic local generation; multiplied by (iii) the appropriate powerflow distribution factor. Factor (2)(a) in the calculation of net system benefit shall equal the product of (iv) the applicable shadow price multiplied by (v) the total load outside the relevant congested area (in MW), less (vi) economic generation located outside the constrained area, multiplied by (vii) the appropriate powerflow distribution factor. For purposes of this calculation, total load outside the relevant congested area shall mean the sum of the loads at each bus on the Transmission System that is not subject to the relevant constraint, multiplied by the appropriate powerflow distribution factor, excluding load at each bus that has a distribution factor greater than -3% relative to the constraint, and economic generation shall mean generation located outside the constrained area that has a distribution factor greater than -3% relative to the constraint, but which otherwise meets the criteria of Section 1.5.7(c)(2)(C)(i) above.

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(C) The assessment of whether a potential transmission upgrade would be cost-effective shall be based on comparison of the net present value of the total estimated net system benefit with the net present value of the total estimated cost of the facility. The net present value of the total estimated net system benefit shall be calculated based on the estimated net system benefit for a period of ten years from the date the Office of the Interconnection estimates the facility could be placed in service and the same discount rate used in the net present value calculation described in the following sentence. The net present value of the total estimated cost of the facility shall be calculated based on the Office of the Interconnections estimate of the capital cost of the potential upgrade and estimated annual operation and maintenance costs associated with the facility, discounted at a rate equal to the total return on investment component included in the annual carrying charge rate and over the depreciation life stated by the applicable Transmission Owner(s) in Schedule 12A of the PJM Tariff or any successor or similar schedule stating such factors with respect to Required Transmission Enhancements, provided that, in the event that no such factors are stated in the PJM Tariff at the time of the assessment under this paragraph (d)(4), the Office of the Interconnection shall determine a reasonable discount rate to use in its net present value calculations. The Office of the Interconnection shall deem the proposed transmission upgrade to be cost-effective if the net present value of the facilitys total estimated net system benefit exceeds the net present value of the facilitys total estimated cost.

(5) The Office of the Interconnection shall review each Interconnection Request pending under Part IV of the PJM Tariff at the time a Market Window is opened under paragraph (d)(3) above, and each Interconnection Request it receives during such Market Window, to evaluate whether the project proposed in the request could resolve, in whole or in part, and provided that the Interconnection Customer proposing such project accepts and maintains designation as a market solution under Sections 36A or 41A of the PJM Tariff and executes the agreement(s) required thereunder, the unhedgeable congestion for which the Market Window was established. In the event that such a proposed project could resolve the unhedgeable congestion in whole or in part, the Office of the Interconnection shall include in its ongoing cost-benefit analysis alternative cases reflecting the expected effect of such project.

(e)(1) In the event that, at the close of a Market Window, an Interconnection Request under Part IV of the PJM Tariff is then pending for a project that, in the Office of the Interconnections judgment, would resolve the unhedgeable congestion in whole or in part, and provided that the Interconnection Customer proposing such project accepts and maintains designation as a market solution under Sections 36A or 41A of the PJM Tariff and executes the agreement(s) required thereunder,then

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such interconnection project shall be deemed to be a market-based response to the unhedgeable congestion and the Office of the Interconnection shall not propose an economic transmission enhancement or expansion to address such unhedgeable congestion, provided, however, that,

(A) should the Office of the Interconnections cost-benefit analysis indicate that a transmission enhancement or expansion in addition to such interconnection project would cost-effectively relieve any portion of the unhedgeable congestion that the interconnection proposal would not relieve, the Office of the Interconnection shall propose to include such an enhancement or expansion in the Regional Transmission Expansion Plan; and

(B) in the event that the Interconnection Request of any interconnection project designated as a market solution pursuant to the PJM Tariff is subsequently terminated or withdrawn, or that the projects designation as a market solution under the PJM Tariff otherwise is terminated or revoked, the Office of the Interconnection shall promptly determine whether to include in the Regional Transmission Expansion Plan a cost-effective transmission enhancement or expansion to resolve the unhedgeable congestion.

(2) In the event that a Market Window closes and no market-based response to the unhedgeable congestion (as described in paragraph (e)(1) above) has been proposed, the Office of the Interconnection shall propose to include in the Regional Transmission Expansion Plan a cost-effective transmission enhancement or expansion, consistent with its cost-benefit analysis under paragraph (d) above, to resolve the unhedgeable congestion.

(f) On each occasion when the Office of the Interconnection, upon the close of a Market Window and otherwise in accordance with this Section 1.5.7, shall propose to include in the Regional Transmission Expansion Plan an economic transmission enhancement or expansion to relieve unhedgeable congestion, it shall complete, in the shortest practical time after the close of the applicable Market Window, the following steps before recommending such an enhancement or expansion to the PJM Board:

(1) Based on unhedgeable congestion experienced through the end of the Market Window, finalize its cost-benefit analysis and the economic transmission enhancement or expansion that it will recommend to the Board;

(2) Upon reasonable notice, convene a meeting open to all interested stakeholders, at which the Office of the Interconnection shall review and discuss with stakeholders its cost-benefit analysis, the economic transmission enhancement or expansion that the Office of the Interconnection proposes to recommend to include in the regional plan, and the Office of the Interconnections proposed allocations, consistent with paragraphs (f) and (g) of Section 1.5.6 above, of responsibility to construct and own or finance and of responsibility to bear, or to pay charges for collection of, the costs of such enhancement or expansion;

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(3) After making any refinements to its recommendation based on stakeholder input that it deems advisable, present its recommended economic transmission enhancement or expansion to the PJM Board for approval as part of the Regional Transmission Expansion Plan.

(g) Any economic transmission enhancement or expansion that becomes part of the Regional Transmission Expansion Plan in accordance with this Section 1.5.7 shall be deemed to be placed in the interconnection queue under Part IV of the PJM Tariff as an Interconnection Request with a priority date equivalent to the close of the Market Window associated with such project.

1.6 Approval of the Final Regional Transmission Expansion Plan.

(a) The PJM Board shall approve the final Regional Transmission Expansion Plan, including any alternatives therein, and any additions of economic transmission enhancements or expansions pursuant to Sections 1.5.6(d) and 1.5.7 above, in accordance with the requirements of this Section 1.6. The Office of the Interconnection shall publish the current, approved Regional Transmission Expansion Plan on the PJM Internet site. Within 30 days after each occasion when the PJM Board approves a Regional Transmission Expansion Plan, or an addition to such a plan, that designates one or more Transmission Owners to construct an economic expansion or enhancement developed pursuant to Sections 1.5.6(d) and 1.5.7 above, the Office of the Interconnection shall file with FERC a report identifying the economic expansion or enhancement, its estimated cost, the entity or entities that will be responsible for constructing and owning or financing the project, and the market participants designated under Section 1.5.6(g) above to bear responsibility for the costs of the project.

(b) If a Regional Transmission Expansion Plan is not approved, or if the transmission service requested by any entity is not included in an approved Regional Transmission Expansion Plan, nothing herein shall limit in any way the right of any entity to seek relief pursuant to the provisions of Section 211 of the Federal Power Act.

(c) Following PJM Board approval, the final Regional Transmission Expansion Plan shall be submitted to the Applicable Reliability Council for verification that all enhancements or expansions conform with or exceed all reliability principles and standards of the Applicable Regional Reliability Council.

1.7 Obligation to Build.

(a) Subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the availability of required financing, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, Transmission Owners designated as the appropriate entities to construct, own and/or finance enhancements or expansions specified in the Regional Transmission Expansion Plan shall construct, own and/or finance such facilities or enter into appropriate contracts to fulfill such obligations. However, nothing herein shall require any Transmission Owner to construct, finance or own any enhancements or expansions specified in the Regional Transmission Expansion Plan for which the plan designates an entity other than a Transmission Owner as the appropriate entity to construct, own and/or finance such enhancements or expansions.

(b) Nothing herein shall prohibit any Transmission Owner from seeking to recover the cost of enhancements or expansions on an incremental cost basis or from seeking approval of such rate treatment from any regulatory agency with jurisdiction over such rates.

(c) The Office of the Interconnection shall be obligated to collect on behalf of the Transmission Owner(s) all charges established under Schedule 12 of the PJM Tariff in connection with facilities which the Office of the Interconnection designates one or more Transmission Owners to build pursuant to this Regional Transmission Expansion Planning Protocol. Such charges shall compensate the Transmission Owner(s) for all costs related to such RTEP facilities under a FERC-approved rate and will include any FERC-approved incentives.

(d) In the event that a Transmission Owner declines to construct an economic transmission enhancement or expansion developed under Sections 1.5.6(d) and 1.5.7 of this Schedule 6 that such Transmission Owner is designated by the Regional Transmission Expansion Plan to construct (in whole or in part), the Office of the Interconnection shall promptly file with the FERC a report on the results of the pertinent economic planning process in order to permit the FERC to determine what action, if any, it should take.

1.8 Relationship to the PJM Open Access Transmission Tariff.

Nothing herein shall modify the rights and obligations of an Eligible Customer or a Transmission Customer, as those terms are defined in the PJM Tariff, with respect to required studies and completion of necessary enhancements or expansions. An Eligible Customer or Transmission Customer electing to follow the procedures in the PJM Tariff instead of the procedures provided herein, shall also be responsible for the related costs. The enhancement and expansion study process under this Protocol shall be funded as a part of the operating budget of the Office of the Interconnection.

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SCHEDULE 7

UNDERFREQUENCY RELAY OBLIGATIONS AND CHARGES

1. UNDERFREQUENCY RELAY OBLIGATION

1.1 Application.

The obligations of this Schedule apply to each Member that is an Electric Distributor, whether or not that Member participates in the Electric Distributor sector on the Members Committee or meets the eligibility requirements for any other sector of the Members Committee.

1.2 Obligations.

(a) Each Electric Distributor in the MAAC Control Zone shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 58.9 Hz and 58.5 Hz. Upon the request of the Members Committee, each Electric Distributor in the MAAC Control Zone shall document that it has complied with the requirement for underfrequency load shedding relays.

(b) Each Electric Distributor in the PJM West Region shall install or contractually arrange for underfrequency relays to interrupt at least 25 percent of its peak load with 5 percent of the load interrupted at each of five frequency levels: 59.5 Hz, 59.3 Hz, 59.1 Hz, 58.9 Hz, and 58.7 Hz; provided, however, that each Electric Distributor in the MAIN Control Zone shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 59.0 Hz, and 58.7 Hz. Upon the request of the Reliability Committee established by the Reliability Assurance Agreement-West, each Electric Distributor in the PJM West Region shall document that it has complied with the requirement for underfrequency load shedding relays.

2. UNDERFREQUENCY RELAY CHARGES

If an Electric Distributor is determined to not have the required underfrequency relays, it shall pay an underfrequency relay charge of:

Charge = D x R x 365

where

D = the amount, in megawatts, the Electric Distributor is deficient; and

R = the daily rate per megawatt, which shall be based on the annual carrying charges for a new combustion turbine generator, installed and connected to the transmission system, which daily deficiency rate as of the Effective Date shall be $58.400/per kilowatt-year or $160 per megawatt-day.

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3. DISTRIBUTION OF UNDERFREQUENCY RELAY CHARGES

3.1 Share of Charges.

Each Electric Distributor that has complied with the requirements for underfrequency relays imposed by this Agreement during a Planning Period, without incurring an underfrequency relay charge, shall share in any underfrequency relay charges paid by any other Electric Distributor that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the number of megawatts of a Electric Distributors load in the most recently completed month at the time of the peak for the PJM Region during that month rounded to the next higher whole megawatt, as established initially on the Effective Date and as updated at the beginning of each month thereafter.

3.2 Allocation by the Office of the Interconnection.

In the event all of the Electric Distributors have incurred underfrequency relay charges during a Planning Period, the underfrequency relay charges shall be distributed among the Electric Distributors on an equitable basis as determined by the Office of the Interconnection.

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SCHEDULE 8

DELEGATION OF PJM CONTROL AREA RELIABILITY RESPONSIBILITIES

1. DELEGATION

The following responsibilities shall be delegated to the Office of the Interconnection by the parties to the Reliability Assurance Agreement.

2. NEW PARTIES

With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Control Area, including entities whose participation in the Agreement will expand the boundaries of the PJM Control Area, such evaluation to be conducted in accordance with the requirements of the Reliability Assurance Agreement; and

(b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement.

3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT

With regard to the implementation of the provisions of the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement and other owners of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards, as the foregoing terms are defined in the Reliability Assurance Agreement;

(c) Monitor the compliance of each party to the Reliability Assurance Agreement with its obligations under the Reliability Assurance Agreement;

(d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement and distribute those charges in accordance with the terms of the Reliability Assurance Agreement;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Collect and maintain generator availability data;

(h) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement;

(i) Coordinate maintenance schedules for generation resources operated as part of the PJM Control Area;

(j) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Control Area or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Control Area;

(k) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Control Area or in a Control Area interconnected with the PJM Control Area and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Control Area; and

(l) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or MAAC principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM Control Area in accordance with Good Utility Practice.

SCHEDULE 8A

DELEGATION OF PJM WEST REGION RELIABILITY RESPONSIBILITIES

1. DELEGATION

The following responsibilities shall be delegated to the Office of the Interconnection by the parties to the Reliability Assurance Agreement-West.

2. NEW PARTIES

With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement-West, the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM West Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region, such evaluation to be conducted in accordance with the requirements of the Reliability Assurance Agreement-West; and

(b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement-West.

3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT-WEST

With regard to the implementation of the provisions of the Reliability Assurance Agreement-West, the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement-West and other owners of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the capacity obligations imposed under the Reliability Assurance Agreement-West;

(c) Monitor the compliance of each party to the Reliability Assurance Agreement-West with its obligations under the Reliability Assurance Agreement-West;

(d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement-West and distribute those charges in accordance with the terms of the Reliability Assurance Agreement-West;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Capacity Resources consistent with the requirements of the Reliability Assurance Agreement-West;

(g) Collect and maintain generator availability data;

(h) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement-West;

(i) Coordinate maintenance schedules for generation resources operated as part of the PJM West Region;

(j) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM West Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM West Region;

(k) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(l) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or ECAR principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM West Region in accordance with Good Utility Practice.

IssuedBy:	Craig Glazer Vice President, Governmental Policy	Effective:	June 1, 2003
IssuedOn:	April 1, 2003		

SCHEDULE 9

PJM CONTROL AREA EMERGENCY PROCEDURE CHARGES

1. EMERGENCY PROCEDURE CHARGE

1.1 Following an Emergency, the compliance of each Member with the instructions of the Office of the Interconnection shall be evaluated by the Office of the Interconnection. If, based on such evaluation, it is determined that a Member failed to comply with the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Member shall demonstrate that it employed its best efforts to comply with such instructions. In the event a Member failed to employ its best efforts to comply with the instructions of the Office of the Interconnection, that Member shall pay (unless otherwise paid by the Member under the Reliability Assurance Agreement an emergency procedure charge as follows:

(a) For each megawatt of voltage reduction that was not implemented as directed, despite being capable of implementation, the Member shall pay 365 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11 of the Reliability Assurance Agreement;

(b) For each megawatt of load that was not dropped as directed, the Member shall pay 730 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11 of the Reliability Assurance Agreement; and

(c) For each megawatt of ALM (as defined in the Reliability Assurance Agreement) that was not implemented as directed and for each megawatt of a Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM Control Area in the case of a Capacity Resource located outside of the PJM Control Area, the Party shall pay 365 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11 of the Reliability Assurance Agreement.

2. DISTRIBUTION OF EMERGENCY PROCEDURE CHARGES

2.1 Complying Parties.

Each Member that has complied with the emergency procedures imposed by this Agreement during an Emergency, without incurring an emergency procedure charge, shall share in any emergency procedure charges paid by any other Member that has failed to satisfy said obligation during such Emergency in an equitable manner to be determined by the PJM Board.

2.2 All Parties.

In the event all of the Members have incurred emergency procedure charges with respect to an Emergency, the emergency procedure charges related to that Emergency shall be distributed in an equitable manner as directed by the PJM Board.

SCHEDULE 9A

PJM WEST REGION EMERGENCY PROCEDURE CHARGES

1. EMERGENCY PROCEDURE CHARGE

1.1 Following an Emergency, the compliance of each Member with the instructions of the Office of the Interconnection shall be evaluated by the Office of the Interconnection. If, based on such evaluation, it is determined that a Member failed to comply with the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Member shall demonstrate that it employed its best efforts to comply with such instructions. In the event a Member failed to employ its best efforts to comply with the instructions of the Office of the Interconnection, that Member shall pay (unless otherwise paid by the Member under the Reliability Assurance Agreement-West) an emergency procedure charge as follows:

(a) For each megawatt of voltage reduction that was not implemented as directed, despite being capable of implementation, the Member shall pay 365 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11 of the Reliability Assurance Agreement-West;

(b) For each megawatt of load that was not dropped as directed, the Member shall pay 730 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11 of the Reliability Assurance Agreement-West; and

(c) For each megawatt of ALM (as defined in the Reliability Assurance Agreement-West) that was not interrupted as directed and for each megawatt of a Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM West Region in the case of a Capacity Resource located outside of the PJM West Region, the Party shall pay 365 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11 of the Reliability Assurance Agreement-West.

2. DISTRIBUTION OF EMERGENCY PROCEDURE CHARGES

2.1 Complying Parties.

Each Member that has complied with the emergency procedures imposed by this Agreement during an Emergency, without incurring an emergency procedure charge, shall share in any emergency procedure charges paid by any other Member that has failed to satisfy said obligation during such Emergency in an equitable manner to be determined by the PJM Board.

2.2 All Parties.

In the event all of the Members have incurred emergency procedure charges with respect to an Emergency, the emergency procedure charges related to that Emergency shall be distributed in an equitable manner as directed by the PJM Board.

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SCHEDULE 10 -

FORM OF NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the Agreement) is made this _day of _, 2004, by and between _, an Authorized Person, as defined below, of _(the State Commission) having jurisdiction within the State of _, with offices at _and PJM Interconnection, L.L.C., a Delaware limited liability company, with offices at 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, PA 10403 (PJM). The State Commission and PJM shall be referred to herein individually as a Party, or collectively as the Parties.

RECITALS

Whereas , PJM serves as the Regional Transmission Organization with reliability and/or functional control responsibilities over transmission systems involving fourteen states including the District of Columbia, and operates and oversees wholesale markets for electricity pursuant to the requirements of the PJM Tariff and the Operating Agreement, as defined below; and

Whereas, the PJM Market Monitor serves as the monitor for PJMs wholesale markets for electricity, and

Whereas , the Operating Agreement requires that PJM and the PJM Market Monitor maintain the confidentiality of Confidential Information; and

Whereas , the Operating Agreement requires PJM and the PJM Market Monitor to disclose Confidential Information to Authorized Persons upon satisfaction of conditions stated in the Operating Agreement, including, but not limited to, the execution of this Agreement by the Authorized Person and the maintenance of the confidentiality of such information pursuant to the terms of this Agreement; and

Whereas , PJM desires to provide Authorized Persons with the broadest possible access to Confidential Information, consistent with PJMs and the PJM Market Monitors obligations and duties under the PJM Operating Agreement, the PJM Tariff and other applicable FERC directives; and

Whereas , this Agreement is a statement of the conditions and requirements, consistent with the requirements of the Operating Agreement, whereby PJM or the PJM Market Monitor may provide Confidential Information to the Authorized Person.

NOW, THERFORE , intending to be legally bound, the Parties hereby agree as follows:

1. DEFINITIONS.

1.1 **Affected Member.** A Member of PJM which as a result of its participation in PJMs markets or its membership in PJM provided Confidential Information to PJM, which Confidential Information is requested by, or is disclosed to an Authorized Person under this Agreement.

1.2 **Authorized Commission.** (i) A State (which shall include the District of Columbia) public utility commission within the geographic limits of the PJM Region (as that term in defined in the Operating Agreement) that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

1.3 **Authorized Person.** A person, including the undersigned, which has executed this Agreement and is authorized in writing by an Authorized Commission to receive and discuss Confidential Information. Authorized Persons may include attorneys representing an Authorized Commission, consultants and/or contractors directly employed or retained by an Authorized Commission, provided however that consultants or contractors may not initiate requests for Confidential Information from PJM or the PJM Market Monitor

1.4 **Confidential Information.** Any information that would be considered non-public or confidential under the Operating Agreement.

1.5 **FERC.** The Federal Energy Regulatory Commission.

1.6 **Information Request.** A written request, in accordance with the terms of this Agreement for disclosure of Confidential Information pursuant to Section 18.17.4 of the Operating Agreement.

1.7 **Operating Agreement.** The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., as it may be further amended or restated from time to time.

1.8 **PJM Market Monitor.** The Market Monitoring Unit established under Attachment M to the PJM Tariff.

1.9 **PJM Tariff.** The PJM Open Access Transmission Tariff, as it may be amended from time to time.

1.10 **Third Party Request.** Any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

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2. Protection of Confidentiality.

Duty to Not Disclose. The Authorized Person represents and warrants that he or she: (i) is presently an Authorized Person as defined herein; (ii) is duly authorized to enter into and perform this Agreement; (iii) has adequate procedures to protect against the release of Confidential Information, and (iv) is familiar with, and will comply with, all such applicable State Commission procedures. The Authorized Person hereby covenants and agrees on behalf of himself or herself to deny any Third Party Request and defend against any legal process which seeks the release of Confidential Information in contravention of the terms of this Agreement.

Conditions Precedent. As a condition of the execution, delivery and effectiveness of this Agreement by PJM and the continued provision of Confidential Information pursuant to the terms of this Agreement, the Authorized Commission shall, prior to the initial oral or written request for Confidential Information by an Authorized Person on its behalf, provide PJM with: (a) a final order of FERC prohibiting the release by the Authorized Person or the State Commission of Confidential Information in accordance with the terms of the Operating Agreement and this Agreement; and (b) either an order of the State Commission or a certification from counsel to the State Commission, confirming that the State Commission has statutory authority to protect the confidentiality of the Confidential Information from public release or disclosure and from release or disclosure to any other entity, and that it has adequate procedures to protect against the release of Confidential Information; and (c) confirmation in writing that the Authorized Person is authorized by the State Commission to enter into this Agreement and to receive Confidential Information under the Operating Agreement. PJM and the PJM Market Monitor shall be expressly entitled to rely upon such FERC and State Commission orders and/or certifications of counsel in providing Confidential Information to the Authorized Person, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder or pursuant to the Operating Agreement, due to the ineffectiveness of the FERC and/or State Commission orders, or the inaccuracy of such certification of counsel.

Discussion of Confidential Information with other Authorized Persons . The Authorized Person may discuss Confidential Information with other Authorized Persons who have executed non-disclosure agreements with PJM containing the same terms and conditions as this Agreement; provided, however, that PJM shall have confirmed in advance and in writing that PJM has previously released the Confidential Information in question to such Authorized Persons. PJM shall respond to any written request for confirmation within two (2) business days of its receipt.

2.4 **Defense Against Third Party Requests.** The Authorized Person shall defend against any disclosure of Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Person shall provide PJM, and PJM shall provide each Affected Member, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with PJM and/or any Affected Member in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Person agrees to furnish only that portion of the Confidential Information which their legal counsel advises PJM (and of which PJM shall, in turn, advise any Affected Members) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

2.5 Care and Use of Confidential Information.

2.5.1 **Control of Confidential Information.** The Authorized Person(s) shall be the custodian(s) of any and all Confidential Information received pursuant to the terms of this Agreement from PJM or the PJM Market Monitor.

2.5.2 **Access to Confidential Information.** The Authorized Person shall ensure that Confidential Information received by that Authorized Person is disseminated only to those persons publicly identified as Authorized Persons on Exhibit A to the certification provided by the State Commission to PJM pursuant to the procedures contained in section 2.3 of this Agreement.

2.5.3 Schedule of Authorized Persons.

(i) The Authorized Person shall promptly notify PJM of any change that would affect the Authorized Persons status as an Authorized Person, and in such event shall request, in writing, deletion from the schedule referred to in section (ii), below.

(ii) PJM shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on the PJM website and/or by written request. Such schedule shall be compiled by PJM, based on information provided by any Authorized Person and/or Authorized Commission. PJM shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by PJM in the compilation and/or maintenance of the schedule.

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2. **Use of Confidential Information.** The Authorized Person shall use the Confidential Information solely for the purpose of
5. assisting the State Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets,
4 operations, transmission planning and siting and generation planning and siting materially affecting retail customers within the State, and for no other purpose.

2. **Return of Confidential Information.** Upon completion of the inquiry or investigation referred to in the Information Request, or
5. for any reason the Authorized Person is, or will no longer be an Authorized Person, the Authorized Person shall (a) return the
5 Confidential Information and all copies thereof to PJM, or (b) provide a certification that the Authorized Person has destroyed all paper copies and deleted all electronic copies of the Confidential Information. PJM may waive this condition in writing if such Confidential Information has become publicly available or non-confidential in the course of business or pursuant to the PJM Tariff, PJM rule or order of the FERC.

2. **Notice of Disclosures.** The Authorized Person, directly or through the Authorized Commission, shall promptly notify PJM,
5. and PJM shall promptly notify any Affected Member, of any inadvertent or intentional release or possible release of the
6 Confidential Information provided pursuant to this Agreement. The Authorized Person shall take all steps to minimize any further release of Confidential Information, and shall take reasonable steps to attempt to retrieve any Confidential Information that may have been released.

Ownership and Privilege. Nothing in this Agreement, or incident to the provision of Confidential Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by PJM, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of PJM and/or the Affected Member.

3. Procedure for Information Requests

Written Requests. Information Requests to PJM shall be in writing, which shall include electronic communications, addressed to the PJM Market Monitor or other PJM representatives as specified by PJM, with a concurrent copy to PJMs General Counsel, and shall: (a) describe with particularity the information sought; (b) provide a description of the purpose of the Information Request; (c) state the time period for which information is requested; and (d) re-affirm that only the Authorized Person shall have access to the Confidential Information requested. PJM shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request of the Authorized Person as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

Oral Disclosures by the PJM Market Monitor. The PJM Market Monitor or other PJM representatives as specified by PJM may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the State Commission to determine whether additional Information Requests for information are appropriate. The PJM Market Monitor or other PJM representative will not make any written or electronic disclosures of Confidential Information to the Authorized Person pursuant to this section. In any such discussions, the PJM Market Monitor or other PJM representative shall ensure that the individual or individuals receiving such Confidential Information are Authorized Persons under this Agreement, orally designate Confidential Information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The PJM Market Monitor or other PJM representative shall also be authorized to assist Authorized Persons in interpreting Confidential Information that is disclosed. PJM or the PJM Market Monitor shall (i) maintain a written record of oral disclosures pursuant to this section, which shall include the date of each oral disclosure and the Confidential. Information disclosed in each such oral disclosure, and (ii) provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any Confidential Information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, the identity of the Affected Party must be made available to the Authorized Person within two (2) business days of the initial oral disclosure.

3. Response to Information Requests.
3

3. Subject to the provisions of Section 3.3.2 below, PJM shall supply Confidential Information to the Authorized Person in
3. response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that
1 the requested Confidential Information can be made available within such period; provided however, that in no event shall Confidential Information be released prior to the end of the fourth (4 th) business day without the express consent of the Affected Member. To the extent that PJM can not reasonably prepare and deliver the requested Confidential Information within such five (5) day period, PJM shall, within such period, provide the Authorized Person with a written schedule for the provision of such remaining Confidential Information. Upon providing Confidential Information to the Authorized Person, PJM shall either provide a copy of the Confidential Information to the Affected Member(s), or provide a listing of the Confidential Information disclosed; provided, however, that PJM shall not reveal any Members Confidential Information to any other Member.

3. Notwithstanding section 3.3.1, above, should PJM or an Affected Member object to an Information Request or any portion
3. thereof, PJM or the Affected Member may, within four (4) business days following PJMs receipt of the Information Request,
2 request, in writing (which shall include electronic communication) addressed to the State Commission with a copy to either the Affected Party or PJM, as the case may be, a conference with the State Commission or the State Commissions authorized designee to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the State Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then PJM, the Affected Member or the State Commission may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a fast track complaint and each party shall bear its own costs in connection with such FERC proceeding. If no FERC proceeding regarding the Information Request is commenced by PJM, the Affected Member or the State Commission within such three day period, PJM shall utilize its best efforts to respond to the Information Request promptly.

3. To the extent that a response to any Information Request requires disclosure of Confidential Information of two or more
3. Affected Parties, PJM shall, to the extent possible, segregate such information and respond to the Information Request
3 separately for each Affected Member.

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4. Remedies.

4.1 **Material Breach.** The Authorized Person agrees that release of Confidential Information to persons not authorized to receive it constitutes a breach of this Agreement and may cause irreparable harm to PJM and/or the Affected Member. In the event of a breach of this Agreement by the Authorized Person, PJM shall terminate this Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person hereunder shall thereupon terminate; provided, however, that PJM may restore an individuals status as an Authorized Person after consulting with the Affected Member and to the extent that: (i) PJM determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damages suffered by the Affected Member; or (iii) similar good cause shown. Any appeal of PJMs actions under this section shall be to FERC.

4.2 **Judicial Recourse.** In the event of any breach of this Agreement, PJM and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Information to PJM. The Authorized Person expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Information to PJM.

4.3 **Waiver of Monetary Damages.** No Authorized Person shall have responsibility or liability whatsoever under this Agreement for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of, or in connection with, the release of Confidential Information to persons not authorized to receive it, provided that such Authorized Person is an employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section 4.3 is intended to limit the liability of any person who is not an employee of or a member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

5. Jurisdiction. The Parties agree that (i) any dispute or conflict requesting the relief in sections 4.1, and 4.2(a) above shall be submitted to FERC for hearing and resolution; (ii) any dispute or conflict requesting the relief in section 4.2(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution; and (iii) jurisdiction over all other actions and requested relief shall lie in any court of competent jurisdiction.

6. Notices. All notices required pursuant to the terms of this Agreement shall be in writing, and served upon the following individuals in person, or at the following addresses or email addresses:

If to the Authorized Person:

____

____

____

____

(email address)

with a copy to

____

____

____

____

(email address)

If to PJM:

Market Monitor

PJM Interconnection, LLC

955 Jefferson Avenue

Valley Forge Corporate Center

Norristown, PA 19403

bowrij@pjm.com

with a copy to

General Counsel

955 Jefferson Avenue

Valley Forge Corporate Center

Norristown, PA 19403

hagelj@pjm.com

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7. **Severability and Survival.** In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and the Operating Agreement, the terms of the Operating Agreement shall in all events be controlling. The Authorized Person acknowledges that any and all obligations of the Authorized Person hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Person and their respective Authorized Commission.

8. **Representations.** The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

9. **Third Party Beneficiaries.** The Parties specifically agree and acknowledge that each Member as defined in the Operating Agreement is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

10. **Counterparts.** This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

11. **Amendment.** This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

PJM INTERCONNECTION, L.L.C.	**AUTHORIZED PERSON**
By:	By:
Name:	Name:
Title:	Title:

IssuedBy: Craig Glazer Effective: June 29, 2004
Vice President, Government Policy
IssuedOn: July 28, 2004
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER04-776-000, issued June 28, 2004, 107 FERC 61,322.

SCHEDULE 10A

FORM OF CERTIFICATION

This Certification (the Certification) is given this _day of _, 200 _, by _, a _(the State Commission), to and for the benefit of PJM Interconnection, LLC (PJM) and its Members. The State Commission and PJM shall be referred to herein collectively as the Parties.

Whereas , the State Commission has designated the individuals on attached Exhibit A (the Authorized Persons) to receive Confidential Information from PJM, and

Whereas , the Authorized Persons and PJM have, or will, enter into non-disclosure agreements, governing the rights and obligations of the Authorized Persons, PJM and others regarding the Authorized Persons access to, provision of, use and control of the Confidential Information (the Non-Disclosure Agreements), and

Whereas , as a condition precedent to the execution of the Non-Disclosure Agreements and provision of Confidential Information to the Authorized Persons, the State Commission is required to make certain representations and warranties to PJM, and

Whereas, PJM agrees to provide Confidential Information to the Authorized Persons, in their capacity as agents of the Authorized Commission, subject to the terms of this Certification, the Non-Disclosure Agreements, and an appropriate order of the Federal Energy Regulatory Commission protecting the confidentiality of such data;

Whereas , the Parties desire to set forth those representations and warranties herein.

Now, therefore, the State Commission hereby makes the following representations and warranties, all of which shall be true and correct as of the date of execution of this Certification, and at all times thereafter, and with the express understanding that PJM and any Affected Member shall rely on each representation and/or warranty:

1. **Definitions.** Terms contained, but not defined, herein shall have the definitions or meanings ascribed to such terms in the Non-Disclosure Agreement or the Operating Agreement.

2. **Requisite Authority.**

The State Commission is an Authorized Commission hereby certifying that it has all necessary legal authority to execute, deliver, and perform the obligations in this Certification.

Each Authorized Person is, at the time of the execution of this Certification, an employee of, or consultant to, the State Commission, and has not materially breached any existing or past non-disclosure agreement or obligation, except as has been disclosed by the State Commission to PJM in writing.

The Authorized Persons have, through all necessary action of the State Commission, been appointed and directed by the State Commission to execute and deliver the Non-Disclosure Agreements to PJM and receive Confidential Information on the State Commissions behalf and for its benefit.

The State Commission will, at all times after the provision of Confidential Information to the Authorized Persons, provide PJM with: (i) written notice of any changes in the Authorized Persons qualification as an Authorized Person within two (2) business days of such change; (ii) written confirmation to any inquiry by PJM regarding the status or identification of any specific Authorized Person within two (2) business days of such request, and (iii) periodic written updates, no less often than semi-annually, containing the names of all Authorized Persons appointed by the State Commission.

Protection of Confidential Information.

The State Commission has adequate internal procedures, to protect against the release of any Confidential Information by the Authorized Persons or other employee or agent of the State Commission, and the State Commission and the Authorized Persons will strictly enforce and periodically review all such procedures. In the event that PJM terminates an Agreement with an Authorized Person, and does not restore such individuals status as an Authorized Person, then the State Commission shall review such internal procedures.

The State Commission has legal authority to protect the confidentiality of Confidential Information from public release or disclosure and/or from release or disclosure to any other person or entity, either by the State Commission or the Authorized Persons, as agents of the State Commission.

The State Commission shall ensure that Confidential Information and shall be maintained by, and accessible only to, the Authorized Persons.

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Defense Against Requests for Disclosure. The State Commission shall defend against, and will direct the Authorized Persons to defend against, disclosure of any Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The State Commission shall provide PJM with prompt notice of any such Third Party Request or legal proceedings, and shall consult with PJM and/or any Affected Member in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the State Commission agrees to furnish only that portion of the Confidential Information which their legal counsel advises PJM (and of which PJM shall, in turn, advise any Affected Member) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

Use and Destruction of Confidential Information.

The State Commission shall use, and allow the use of, the Confidential Information solely for the purpose of discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting and generation planning and siting materially affecting retail customers within their respective State, and for no other purpose.

Upon completion of the inquiry or investigation referred to in any Information Request initiated by or on behalf of the State Commission, or for any reason any Authorized Person is, or will no longer be an Authorized Person, the State Commission will ensure that such Authorized Person either (a) returns the Confidential Information and all copies thereof to PJM, or (b) provides a certification that the Authorized Person and/or the State Commission has destroyed all paper copies and deleted all electronic copies of the Confidential Information.

Notice of Disclosure of Confidential Information. The State Commission shall promptly notify PJM of any inadvertent or intentional release or possible release of the Confidential Information provided to any Authorized Person, and shall take all available steps to minimize any further release of Confidential Information and/or retrieve any Confidential Information that may have been released.

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7. **Release of Claims.** PJM and the PJM Market Monitor shall be expressly entitled to rely upon any orders of FERC and/or the State Commission or certifications of counsel for the State Commission, in providing Confidential Information to the Authorized Persons, and shall in no event be liable, or subject to damages or claims of any kind or nature due to the ineffectiveness or inaccuracies of such orders, or the inaccuracy of such certification of counsel, or PJM or the PJM Market Monitors reliance on such orders, and the State Commission hereby waives any such claim, now or in the future, whether known or unknown.

8. **Ownership and Privilege.** Nothing in this Certification, or incident to the provision of Confidential Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by PJM, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of PJM and/or the Affected Member.

Executed , as of the date first set out above.

[Commission]
By:
Its:

SEE NEXT PAGE

EXHIBIT A

CERTIFICATION

LIST OF AUTHORIZED PERSONS

Name Authority	MailingAddress	Email	Tel#	ScopeandDurationof

Issued By: Craig Glazer Effective: June 29, 2004
Vice President, Government Policy
Issued On: April 29, 2004

SCHEDULE 11

PJM CAPACITY CREDIT MARKETS IN PJM REGION

1. PURPOSES AND OBJECTIVES

1.1 PJM Capacity Credit Markets in PJM Region.

This Schedule sets forth the procedures applicable to the operation of the PJM Capacity Credit Markets in the PJM Region. The PJM Capacity Credit Markets will allow Market Participants to buy and sell Capacity Credits at market clearing prices that are established by the PJM Capacity Credit Markets and made public by the Office of the Interconnection. The PJM Capacity Credit Markets shall be administered by the Office of Interconnection in accordance with the principles and procedures specified in this Schedule.

1.2 [Reserved.]

1.3 Use of Capacity Credits.

An entity may use Capacity Credits to meet all or part of its capacity obligations imposed under the Reliability Assurance Agreement or Reliability Assurance Agreement-West. Such Capacity Credits may be used by themselves, or along with any other options for meeting capacity obligations imposed under the Reliability Assurance Agreement or Reliability Assurance Agreement-West.

2. DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used in this Schedule shall have the respective meanings assigned herein or in the Agreement for all purposes of this Schedule (such definitions to be equally applicable to both the singular and the plural forms of the terms defined).

2.1 Buy Bid.

Buy Bid shall mean a bid to buy Capacity Credits in a PJM Capacity Credit Market.

2.2 Capacity Credit.

Capacity Credit shall mean an entitlement to a specified number of megawatts of Unforced Capacity from a Capacity Resource for the purpose of satisfying capacity obligations imposed under the Reliability Assurance Agreement or Reliability Assurance Agreement-West, such entitlement not to include any entitlement to the output of the Capacity Resource. Solely for purposes of the PJM Installed Capacity Credit Markets, the term Capacity Credit also shall refer to credits for Installed Capacity during the Interim Period for the ComEd Zone.

2.2A ComEd Zone.

ComEd Zone shall have the meaning specified in Schedule 17 of the Reliability Assurance Agreement-West.

2.3 Capacity Resources.

Capacity Resources shall have the meaning specified in the Reliability Assurance Agreement and Reliability Assurance Agreement-West.

2.4 Holiday.

Holiday shall mean a federal or state holiday designated by the Office of the Interconnection for recognition in the conduct of PJM Daily Capacity Credit Markets.

2.4A Installed Capacity.

Installed Capacity shall have the meaning specified in Schedule 17 of the Reliability Assurance Agreement-West.

2.4B Interim Period.

Interim Period shall have the meaning specified in Schedule 17 of the Reliability Assurance Agreement-West.

2.5 PJM Capacity Credit Market.

PJM Capacity Credit Market shall mean the PJM Daily Capacity Credit Market and the PJM Monthly Capacity Credit Market.

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2.6 PJM Daily Capacity Credit Market.

PJM Daily Capacity Credit Market shall mean a competitive market, administered by the Office of the Interconnection in accordance with the provisions of this Schedule, for the purchase and sale of Capacity Credits for the business day following the day on which the market is conducted or for an intervening weekend day or Holiday.

2.6A PJM Installed Capacity Credit Market.

PJM Installed Capacity Credit Market shall mean a competitive market, administered by the Office of the Interconnection in accordance with the provisions of this Schedule, for the purchase and sale of credits for Installed Capacity for the Interim Period, or any month thereof, in the ComEd Zone.

2.7 PJM Monthly Capacity Credit Market.

PJM Monthly Capacity Credit Market shall mean a competitive market, administered by the Office of the Interconnection in accordance with the provisions of this Schedule, for the purchase and sale of Capacity Credits for each or any of the twelve months following the month during which the market is conducted. Solely for purposes of the ComEd Zone during the Interim Period, PJM Monthly Capacity Credit Markets also shall refer to separate monthly PJM Installed Capacity Credit Markets.

2.8 Sell Offer.

Sell Offer shall mean an offer to sell Capacity Credits in a PJM Capacity Credit Market.

2.9 Unforced Capacity.

Unforced Capacity shall have the meaning specified in the Reliability Assurance Agreement and Reliability Assurance Agreement-West.

2.10 Up-To Block.

Up-To Block shall mean a Sell Offer or Buy Bid for a quantity of Capacity Credits equal to or less than a specified quantity.

3. PARTICIPATION IN THE PJM CAPACITY CREDIT MARKET

3.1 Eligibility.

A Member shall become eligible to participate in any of the PJM Capacity Credit Markets by becoming a Market Buyer or a Market Seller, or both as may be appropriate, in accordance with the provisions of Schedule 1 of the Agreement. In order to participate in any of the PJM Capacity Credit Markets, a Market Buyer also either must be (a) an entity that is or will become a Load Serving Entity in the PJM Region and a party to the Reliability Assurance Agreement or Reliability Assurance Agreement-West, or (b) have a contractual obligation to sell capacity (including sales for resale) which will be used in the PJM Region. A Market Seller may participate in any PJM Capacity Credit Market only to the extent that it has Capacity Credits available to sell in excess of its capacity obligation imposed under the Reliability Assurance Agreement or Reliability Assurance Agreement-West and other contractual obligations to sell capacity (including sales for resale), as determined in accordance with Section 6.1.3.

3.2 Effect of Withdrawal.

Withdrawal from the Agreement shall not relieve a Market Participant of any obligation to furnish or pay for Capacity Credits incurred in connection with participation in a PJM Capacity Credit Market prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions or events occurring prior to such withdrawal; and provided, further, that withdrawal from this

Agreement shall not relieve any Market Participant of any obligations it may have under, or constitute withdrawal from, any Related PJM Agreement.

4. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

4.1 Operation of the PJM Capacity Credit Market.

The Office of the Interconnection shall operate the PJM Capacity Credit Markets in accordance with the provisions of this Schedule and applicable provisions of the Agreement, the Reliability Assurance Agreement, and the Reliability Assurance Agreement-West. Operation of the PJM Capacity Credit Markets shall include, but not be limited to, provision of the following services:

i) Determining the qualification of entities to become Market Participants;

ii) Administering the PJM Capacity Credit Markets;

iii) Accounting for PJM Capacity Credit Market transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in the PJM Capacity Credit Markets;

iv) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of PJM Capacity Credit Market transactions, as may be appropriate to the administration of the PJM Capacity Credit Markets; and

v) Monitoring compliance of participants in the PJM Capacity Credit Markets with the provisions of this Schedule and the Agreement.

4.2 Records and Reports.

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the PJM Capacity Credit Markets. For each day of operation of the PJM Capacity Credit Markets, the Office of the Interconnection shall publish, as specified below: (i) the price, if determined, at which the PJM Capacity Credit Market cleared; (ii) the total volume of Capacity Credits purchased; and (iii) such other PJM Capacity Credit Market data as may be appropriate to the efficient and competitive operation of the PJM Capacity Credit Markets, consistent with preservation of the confidentiality of commercially sensitive or proprietary information. Publication of the foregoing information shall be by posting on the PJM web site. Such information shall remain available on the PJM web site for twelve months from the date of posting. The Office of the Interconnection shall not disclose commercially sensitive or proprietary information in any report or web site posting.

5. GENERAL PROVISIONS

5.1 Market Sellers.

Only Market Sellers shall be eligible to submit Sell Offers. Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Schedule and the Agreement.

5.2 Market Buyers.

Only Market Buyers shall be eligible to submit Buy Bids. Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Schedule and the Agreement.

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5.3 Agents.

A Market Participant may participate in the PJM Capacity Credit Markets through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Capacity Credit Markets through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Capacity Credit Markets, and shall ensure that any such agent complies with the requirements of this Schedule and the Agreement.

5.4 General Obligations of Market Participants.

Each Market Participant shall comply with all laws and regulations applicable to the operation of the PJM Capacity Credit Markets and the use of Capacity Credits, and shall comply with all applicable provisions of this Schedule, the Agreement, and the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and all procedures and requirements for the operation of the PJM Capacity Credit Markets and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

5.5 Relationship of Capacity Credits to Capacity Obligations Imposed under the Reliability Assurance Agreement or Reliability Assurance Agreement-West.

A megawatt of Capacity Credit shall satisfy a megawatt of capacity obligation imposed under the Reliability Assurance Agreement or Reliability Assurance Agreement-West. Capacity Credits purchased from a PJM Capacity Credit Market shall not be adjusted for forced outages or other reasons. Because Capacity Credits are based on Capacity Resources, no further capability or deliverability demonstrations beyond those for the related Capacity Resource shall be required.

5.6 Deficiency Charges.

If the Office of the Interconnection determines that the first Market Seller in a PJM Capacity Credit Market of a Capacity Credit did not have sufficient Unforced Capacity (or Installed Capacity, in the case of the ComEd Zone during the Interim Period) to support the Capacity Credit transaction at the time for which the Capacity Credit was applicable, any such deficiency shall be satisfied through payment of deficiency charges by such first Market Seller calculated as specified in the Reliability Assurance Agreement and Reliability Assurance Agreement-West. Any amounts collected from such deficiency charges shall be distributed in accordance with the Reliability Assurance Agreement and Reliability Assurance Agreement-West.

5.7 Financial Transmission Rights.

Acquisition of a Capacity Credit shall not entitle the holder to a Financial Transmission Right.

5.8 Confidentiality.

The following information submitted to the Office of the Interconnection in connection with any PJM Capacity Credit Market shall be deemed confidential information for purposes of Section 18.17 of the Agreement: (i) the terms and conditions of all Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for capacity or Capacity Credits.

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6. OPERATION OF THE PJM CAPACITY CREDIT MARKETS

6.1 Content of Sell Offers.

6.1.1 Specifications.

Sell Offers shall specify:

i) The quantity of Capacity Credits offered, in increments of 0.1 megawatt;

ii) The minimum price, in dollars and cents per megawatt per day, that will be accepted by the seller;

iii) For a PJM Daily Capacity Credit Market conducted on a Friday or the day before a Holiday, the dates on which the offered Capacity Credits may be used; and

iv) For a PJM Monthly Capacity Credit Market, the month or months for which the offered Capacity Credits may be used.

6.1.2 Market-based Offers.

A Market Seller that is authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers to PJM Capacity Credit Markets that specify market-based prices.

6.1.3 Availability of Capacity Credits for Sale.

i) The Office of the Interconnection shall determine the maximum megawatts of Capacity Credits each Market Seller may offer in a PJM Capacity Credit Market, through verification of the availability of megawatts of capacity from: (a) Capacity Resources owned by or under contract to the Market Seller; (b) rights obtained in bilateral transactions; (c) the results of prior PJM Capacity Credit Markets; and (d) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection may reject Sell Offers or portions of Sell Offers for Capacity Credits determined by it not to be available for sale.

The Office of the Interconnection shall determine the maximum amount of Capacity Credits available for sale in a PJM Capacity Credit Market as of the beginning of the period during which Buy Bids and Sell Offers are accepted for each market. To enable the Office of the Interconnection to make this determination, no bilateral transactions for capacity or Capacity Credits applicable to the period covered by a PJM Capacity Credit Market will be processed from the beginning of the period for submission of Sell Offers and Buy Bids for that market until completion of the clearing determination for that market. Processing of such bilateral transactions will recommence once all sales for that market are deemed final as specified below.

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i In order for a bilateral transaction for the purchase and sale of a Capacity Credit to be processed by the Office of the
i Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer
i
)

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of the Capacity Credit from the seller to the buyer in accordance with procedures established by the Office of the Interconnection.

6.2 Content of Buy Bids.

Buy Bids shall specify:

i) The quantity of Capacity Credits desired, in increments of 0.1 megawatt;

ii) The maximum price, in dollars and cents per megawatt per day, that will be paid by the buyer;

iii) For a PJM Daily Capacity Credit Market conducted on a Friday or the day before a Holiday, the dates for which Capacity Credits are desired; and

iv) For a PJM Monthly Capacity Credit Market, the month or months for which Capacity Credits are desired.

6.3 Submission of Sell Offers and Buy Bids.

The submission of Sell Offers and Buy Bids shall be subject to the following requirements:

i) A Sell Offer or Buy Bid that fails to specify price or quantity, or the date or months for which Capacity Credits are to be used if applicable, shall be rejected by the Office of the Interconnection.

All Sell Offers and Buy Bids are for an Up-To Block.

All Sell Offers and Buy Bids for a PJM Daily Capacity Market must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after that period.

Sell Offers or Buy Bids for a PJM Daily Capacity Credit Market conducted on a Monday, Tuesday, Wednesday, or Thursday that is not the day before a Holiday shall be for capacity credits applicable to the following day.

Sell Offers or Buy Bids for a PJM Daily Capacity Credit Market conducted on a Friday or the day before a Holiday shall designate the date, to and including the next business day, to which the Capacity Credits are applicable. A separate PJM Daily Capacity Credit Market shall be conducted on such Friday or day before a Holiday for Capacity Credits applicable to each following day, to and including the next business day.

Sell Offers and Buy Bids for a PJM Monthly Capacity Credit Market must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection for the conduct of a PJM Monthly Capacity Credit Market. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after that period.

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vSell Offers and Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection;
i provided, however, that if that Internet site cannot be accessed at any time during the period specified in the foregoing
i paragraph, a Sell Offer or Buy Bid may be submitted or withdrawn by a facsimile transmitted to the number specified by the
) Office of the Interconnection.

6.4 Conduct of PJM Capacity Credit Markets.

6.4.1 PJM Daily Capacity Credit Markets.

Each business day, following the submission of Sell Offers and Buy Bids in accordance with the specified deadline for PJM Daily Capacity Credit Markets, a PJM Daily Capacity Credit Market(s) will be conducted. A PJM Daily Capacity Credit Market will clear Sell Offers and Buy Bids for Capacity Credits for use the next business day, and on Fridays or the day before a Holiday, a separate Daily Capacity Credit Market(s) for each intervening weekend day or Holiday shall clear Sell Offers and Buy Bids for Capacity Credits for such days.

6.4.2 PJM Monthly Capacity Credit Markets.

Following the submission of Sell Offers and Buy Bids in accordance with the specified deadline for PJM Monthly Capacity Credit Markets, a PJM Monthly Capacity Credit Market will be conducted. Each such PJM Monthly Capacity Credit Market will clear Sell Offers and Buy Bids for Capacity Credits for use in each of the following twelve months.

6.5 Market Clearing Procedures.

For purposes of the rank ordering and market clearing procedures described below, the Office of the Interconnection will: (a) evaluate all Sell Offers for an Up-To Block at the same price as one Sell Offer for an Up-to Block, with the quantity equal to the total quantity of the equally-priced Sell Offers; and (b) evaluate all Buy Bids for an Up-To Block at the same price as one Buy Bid for an Up-to Block, with the quantity equal to the total quantity of the equally-priced Buy Bids.

The Office of the Interconnection will rank order all Sell Offers and Buy Bids by price. Sell Offers will be ranked by lowest price first and then ranked in ascending price order. Buy Bids will be ranked by highest price first and then ranked in descending price order. In the event that a Market Participant enters one or more Buy Bids with a price higher than the lowest offer price of that Market Participants Sell Offers, then all of the Market Participants Buy Bids priced higher than its lowest priced Sell Offer shall be rejected.

The Office of the Interconnection will determine the largest quantity of Sell Offers and Buy Bids for which the price of the marginal Sell Offer is equal to or less than the price of the marginal Buy Bid. The market will clear at price specified in the marginal Sell Offer.

If a marginal Sell Offer or Buy Bid is a combination of Sell Offers or Buy Bids deemed to be a single Sell Offer or Buy Bid for an Up-To Block as specified above, the quantity purchased or sold will be allocated among the combined Sell Offers or Buy Bids in proportion to the quantities offered in each of the combined Sell Offers or Buy Bids.

If all Sell Offers remaining in the rank order are at prices higher than the highest price of any Buy Bid remaining in the rank order, the market will be cleared with no transactions, and a market clearing price will not be determined.

6.6 Settlement Procedures.

Upon determination of the market clearing price as specified above: (a) all Sell Offers at a price equal to or less than the market clearing price and not removed from the rank ordering and for which there is sufficient Buy Bid demand at or above the market clearing price will be deemed sold at the market clearing price, and all Buy Bids at a price equal to or greater than the market clearing price and not removed from the rank ordering and for which there is sufficient Sell Offer supply at or below the market clearing price will be deemed satisfied at the market clearing price, with any Up-To Blocks split and prorated as may be appropriate; and (b) the

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accounts of Market Sellers and Market Buyers will be credited or debited accordingly. The foregoing determinations shall be made, and all sales and purchases shall be deemed final, as of specified times, as designated by the Office of the Interconnection, on the day on which each PJM Capacity Market is conducted.

6.7 Billing.

The Office of the Interconnection shall prepare a billing statement for each Market Participant in accordance with the charges and credits specified in this Schedule, and showing the net amount to be paid or received by each Market Participant. Billing statements for PJM Daily Capacity Markets shall be rendered following the end of each month for Capacity Credits bought and sold in the month just ended. Billing statements for PJM Monthly Capacity Credit Markets shall be rendered following the end of the month for which the Capacity Credit applies. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participants internal accounting. Payment of statements shall be made in accordance with the Agreement.

6.8 Time Standard.

All deadlines for the submission or withdrawal of Sell Offers or Buy Bids, or for other purposes specified in this Schedule, shall be determined by the time observed in the Eastern time zone.

[Sheet Nos. 206 through 214 are reserved]

Reserved for future use.

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SCHEDULE 12

PJM MEMBER LIST

ACN Energy, Inc.

ACN Power, Inc.

Advantage Energy, Inc.

AES Enterprise, Inc.

AES Ironwood, LLC

Air Products & Chemicals, Inc.

Allegheny Electric Cooperative, Inc.

Allegheny Energy Supply Company, L.L.C.

Allegheny Energy Supply Conemaugh, L.L.C.

Amerada Hess Corporation

AmerGen Energy Company, L.L.C.

American Cooperative Services

American Municipal Power-Ohio, Inc.

American Ref-Fuel Company of Delaware Valley, L.P.

American Ref-Fuel Company of Essex County

American Transmission Systems Inc.

Appalachian Power Company

Aquila Merchant Services, Inc.

Atlantic City Electric Company

Automated Power Exchange, Inc.

Baltimore Gas and Electric Company

Benton Foundry, Inc.

Bethlehem Steel Corporation

BGE Home Products & Services, Inc.

BOC Energy Services, Inc.

BOC Group, Inc. (The)

Borough of Chambersburg

Borough of Ephrata

Borough of Tarentum

BP Energy Company

Calpine Energy Services, L.P.

Calvert Cliffs Nuclear Power Plant, Inc.

Cargill Power Markets, LLC

Carolina Power & Light Company

Carpenter Technology Corporation

Central Hudson Gas & Electric Corporation

Central Power & Light Company

Cincinnati Gas and Electric Company (The)

Cinergy Capital & Trading, Inc.

Cinergy Services, Inc.

Citadel Energy Products, LLC

City of New Martinsville

City of Philippi

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CMS Marketing, Services and Trading Company

Columbia Energy Power Marketing Corporation

Columbus Southern Power Company

Commercial Utility Consultants, Inc.

Commonwealth Chesapeake Company, LLC

Commonwealth Energy Corporation dba electricAMERICA

Conectiv Energy Supply, Inc.

ConEdison Energy, Inc.

Consolidated Edison Company of New York, Inc.

Consolidated Edison Solutions, Inc.

Constellation Energy Source, Inc.

Constellation NewEnergy, Inc.

Constellation Power Source Generation, Inc.

Constellation Power Source, Inc.

Cook Inlet Power, L.P.

Coral Power, L.L.C.

Covanta Energy Group, Inc.

Covanta Union, Inc.

Customized Energy Solutions, Ltd.

Dayton Power & Light Company (The)

Delaware Municipal Electric Corporation

Delmarva Power & Light Company

Detroit Edison Company

Division of the Public Advocate of State of Delaware

Dominion Energy Direct Sales, Inc.

Dominion Energy Marketing, Inc.

Dominion Retail, Inc.

Dominion Virginia Power

Downes Associates, Inc.

DTE Energy Marketing, Inc.

DTE Energy Trading, Inc.

Duke Energy Trading and Marketing, L.L.C.

Duke Power Company

Dynegy Power Marketing, Inc.

E.F. Kenilworth, Inc.

Easton Utilities Commission

ECONnergy Energy Company, Inc.

ECONnergy Pa, Inc.

Edison Mission Marketing and Trading, Inc.

El Paso Merchant Energy, L.P.

Electrotek Concepts, Inc.

EME Homer City Generation, L.P.

Energy East Solutions, Inc.

Engage Energy America L.L.C.

Entergy-Koch Trading, LP

EPEX, Inc.

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Exelon Generation Company, L.L.C.

FirstEnergy Solutions Corp.

Florida Power & Light Company

FMF Energy, Inc.

FPL Energy Power Marketing, Inc.

GPU Advanced Resources, Inc.

Green Mountain Energy Company

Hagerstown Light Department

Handsome Lake Energy, L.L.C.

Harrison REA, Inc.

Hess Energy Inc.

Hess Energy Power & Gas Company, LLC

H.Q. Energy Services (U.S.), Inc.

Indiana Michigan Power Company

Its Electric & Gas, L.L.C.

J. Aron & Company

Jedi Linden NB, L.L.C.

Jersey Central Power & Light Company

Kentucky Power Company

KeySpan Energy Services, Inc.

KeySpan Ravenswood, Inc.

Lebanon Methane Recovery, Inc.

Legacy Energy Group, L.L.C. (The)

Lehigh Portland Cement Company

Letterkenny Industrial Development Authority

Mack Services Group (The)

Maryland Office of Peoples Counsel

Maryland Public Service Commission

Merrill Lynch Capital Services, Inc.

Metropolitan Edison Company

MG Industries

Middlesex Generating Co., L.L.C.

MIECO, Inc.

Mirant Americas Energy Marketing, L.P.

Mirant Americas Retail Energy Marketing, L.P.

Mirant Potomac River, L.L.C.

Monongahela Power Company dba Allegheny Power

Morgan Stanley Capital Group, Inc.

New Power Company (The)

New York State Electric & Gas Corporation

New Jersey Division of the Ratepayer Advocate

NJR Natural Energy Company

Northeast Utilities Service Company

Northern States Power Company

NRG New Jersey Energy Sales LLC

NRG Power Marketing, Inc.

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NYSEG Solutions, Inc.

Occidental Power Marketing, L.P.

Occidental Power Services, Inc.

Office of the Peoples Counsel for the District of Columbia

Ohio Power Company

Old Dominion Electric Cooperative

Orion Power Midwest, L.P.

Outback Power Marketing, Inc.

Panda Power Corporation

PeakTrader, L.L.C.

PECO Energy Company

Pedricktown Cogeneration Limited Partnership

PEI Power Corporation

PEI Power II, L.L.C.

Penn Power Energy, Inc.

Pennsylvania Electric Company

Pennsylvania Office of Consumer Advocate

Pepco Energy Services, Inc.

PG Energy Services Inc. dba PG Energy PowerPlus

PG&E Energy Trading-Power, L.P.

Potomac Edison Company (The) dba Allegheny Power

Potomac Electric Power Company

Potomac Power Resources, Inc.

Powerex Corporation

PPL Brunner Island, L.L.C.

PPL Electric Utilities Corporation dba PPL Utilities

PPL EnergyPlus, L.L.C.

PPL Holtwood, L.L.C.

PPL Martins Creek, L.L.C.

PPL Montour, L.L.C.

PPL Susquehanna, L.L.C.

Praxair, Inc.

Progress Ventures, Inc.

PSEG Energy Resources and Trade LLC

PSEG Energy Technologies, Inc.

PSI Energy, Inc.

Public Service Company of Colorado

Public Service Company of Oklahoma

Public Service Electric & Gas Company

Rainbow Energy Marketing Corporation

Reliant Energy Services, Inc.

Richards Energy Group (The)

Rochester Gas and Electric Corporation

Rockland Electric Company

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RWE Trading Americas, Inc.

Safe Harbor Water Power Corporation

Schuylkill Energy Resources, Inc.

Select Energy, Inc.

Select Energy New York, Inc.

Sempra Energy Solutions

Sempra Energy Trading Corporation

Sheetz, Inc.

Sithe Power Marketing, L.P.

SmartEnergy.com, Inc.

South Carolina Electric & Gas Company

South Jersey Energy Company

South Jersey Energy Solutions, L.L.C.

Southern Maryland Electric Cooperative, Inc.

Southwestern Electric Power Company

Split Rock Energy, LLC

STI Capital Company

Strategic Energy L.L.C.

Sunbury Generation, L.L.C.

Sunoco Power Marketing, L.L.C.

Sunoco, Inc. (R&M)

TEC Trading, Inc.

Tosco Power, Inc.

Town of Front Royal, Virginia

Town of Thurmont, Maryland

Town of Williamsport

Tractebel Energy Marketing, Inc.

TransAlta Energy Marketing (U.S.) Inc.

TXU Energy Trading Company, LP

UBS AG, acting through its London Branch

UGI Energy Services, Inc.

UGI Development Company

UGI Utilities, Inc.

USP&G (Pennsylvania), Ltd.

Utilitech, Inc.

Vineland Municipal Electric Utility

Virginia State Corporation Commission

Washington Gas Energy Services, Inc.

West Penn Power dba Allegheny Power

West Texas Utilities Company

Weyerhaeuser Company

Williams Energy Marketing & Trading Company

WPS Energy Services, Inc.

WPS Westwood Generation, L.L.C.

IssuedBy:	Craig Glazer Vice President, Governmental Policy	Effective:	March 20, 2003
IssuedOn:	March 20, 2003		

RESOLUTION TO AMEND THE

PROCEDURES REQUIRING THE RETENTION OF

AN INDEPENDENT CONSULTANT TO

PROPOSE A LIST OF CANDIDATES

FOR THE BOARD OF MANAGERS ELECTION FOR 2001

1. For the election of Board Members at the Annual Meeting in 2001, an independent consultant to prepare a list of persons qualified and willing to serve on the PJM Board in accordance with Section 7.1 of the Operating Agreement shall not be required.

2. Section 7.1 of the Operating Agreement shall be deemed to be amended by the foregoing for the election at the Annual Meeting in 2001.

3. PJM shall make the necessary regulatory filings with the Federal Energy Regulatory Commission to implement the foregoing.

Exhibit10(c)(2)

PJM WEST RELIABILITY ASSURANCE AGREEMENT

Among

LOAD SERVING ENTITIES

in the

PJM WEST REGION

This version includes compliance Filings and FERC-approved revisions as of October 28, 2004.

PJM WEST

RELIABILITY ASSURANCE AGREEMENT

This PJM West RELIABILITY ASSURANCE AGREEMENT, (hereafter Agreement) dated as of this 14th day of March, 2001, by and among each entity that becomes a Party to this Agreement by executing a counterpart hereof, hereinafter referred to collectively as the Parties and individually as a Party.

WITNESSETH:

WHEREAS, PJM Interconnection, L.L.C., a Delaware limited liability company has amended its operating agreement (the Amended Operating Agreement) to extend its market administration and transmission system operator functional control service to utility systems located outside the current PJM Control Area; and

WHEREAS, certain entities desire to achieve the benefits of reliable electric service by becoming a party to the Amended Operating Agreement and by sharing certain operating reserve requirements and meeting other operating criteria; and

WHEREAS, the Amended Operating Agreement requires that every Load Serving Entity serving load within the PJM West Region become a Party to this Agreement; and

WHEREAS, each Party to this Agreement is a Load Serving Entity within the PJM West Region; and

WHEREAS, each Load Serving Entity is committing to share Capacity Resources with the other Parties to reduce the overall operating reserve requirements for the Parties while maintaining reliable service; and

WHEREAS, PJM Interconnection, L.L.C., is obligated under the Amended Operating Agreement to establish and administer a capacity credit market and perform other responsibilities in order to facilitate the ability of Load Serving Entities to meet their obligations under this Agreement; and

WHEREAS, each Load Serving Entity is committing to provide mutual assistance to the other Parties during Emergencies and to meet other obligations designed to achieve reliable electric service;

NOW THEREFORE, for and in consideration of the covenants and mutual agreements set forth herein and intending to be legally bound hereby, the Parties agree as follows:

ARTICLE 1 DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Accounted-For Obligation shall have the meaning set forth in Schedule 7.

1.1A [Reserved.]

1.2 Agreement shall mean this PJM West Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.3 Amended Operating Agreement shall mean the Operating Agreement of PJM Interconnection, L.L.C. as amended by action of the PJM Members Committee on February 8, 2001, as such agreement may be further amended from time to time.

1.4 Applicable Regional Reliability Council shall mean the reliability council for the region in which a Member operates.

1.4A ALM shall mean active load management in accordance with Schedule 5.2, and includes Qualified Interruptible Load.

1.4B ALM Factor shall mean that factor approved from time to time by the Reliability Committee for use in the determination of credit for ALM in accordance with Schedule 5.2.

1.4C Behind The Meter Generation refers to one or more generating units that are located with load at a single electrical location such that no transmission or distribution facilities owned or operated by any Transmission Owner or Electrical Distributor are used to deliver energy from the generating units to the load; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating units[s] capacity that is designated as a Capacity Resource or (ii) in any hour, any portion of the output of the generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

1.4D Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.4E Capacity Credits shall mean the entitlement to a specified number of megawatts of Unforced Capacity for the purpose of satisfying capacity obligations imposed under this Agreement and that are acquired by a Party through bilateral purchase or pursuant to Schedule 11 of the Amended Operating Agreement, or any successor schedule.

1.5 Capacity Resources shall mean megawatts of net capacity from (i) owned or contracted for generating facilities, all of which are accredited to a Party pursuant to the procedures set forth in Schedules 9 and 10 for purposes of this Agreement and are committed to satisfy that Partys obligations under this Agreement or (ii) net capacity from resources within the PJM Region not owned or contracted for by a party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10 for purposes of this Agreement.

1.6 [Reserved.]

1.7 [Reserved.]

1.8 Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and the applicable regional reliability council of NERC;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.9 [Reserved.]

1.10 ECAR shall mean the reliability council under section 202 of the Federal Power Act, established pursuant to the East Central Area Reliability Coordination Agreement dated June 1, 1968, or any successor thereto.

1.11 Effective Date shall mean January 1, 2002 or such other date as is allowed by the FERC.

1.12 Electric Distributor shall mean an entity that owns, or leases with rights equivalent to ownership, electric distribution facilities that are providing electric distribution service to electric load within the PJM West Region or MAAC Control Zone.

1.13 Emergency shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

1.14 End-Use Customer shall mean a Member that is a retail end-user of electricity within the MAAC Control Zone or PJM West Region.

1.14A FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

IssuedBy: Craig Glazer Effective: June 1, 2003
Vice President, Governmental Policy
IssuedOn: July 29, 2003
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER03-703-000, issued May 30, 2003, 103 FERC 61,250.

1.15 Firm Point-To-Point Transmission Service shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.16 Force Majeure shall mean any act of God, labor disturbance, act of public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Partys control. No Party will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement.

1.17 [Reserved.]

1.17A [Reserved.]

1.18 [Reserved.]

1.18A Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.18B Forecast LSE Obligation (MW) shall mean a Partys obligation established pursuant to Section 6.1.2.

1.18C Forecast Pool Requirement shall mean the amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board, upon the recommendation of the Reliability Committee, pursuant to Schedule 4.

1.18D Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

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IssuedOn:	April 1, 2003		

1.19 Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the MAAC Control Zone or PJM West Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.19A Generator Forced Outage shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of a Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.19B Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.19C Generator Planned Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.20 Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods 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. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.21 [Reserved.]

1.21A Interval shall be the four-month period commencing June 1, the three-month period commencing October 1 , and the five-month period commencing January 1, provided, however, that solely for purposes of Schedule 17 in calendar year 2004, Interval shall include the one month period beginning May 1 rather than the five-month period beginning January 1.

1.21B Interval Deficiency Charge shall be equal to the Deficiency Rate established by the Reliability Committee multiplied by the number of days in each Interval.

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	Vice President, Governmental Policy		
IssuedOn:	December 31, 2003		

1.22 Load Serving Entity or **LSE** shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM West Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM West Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.23 MAAC shall mean the Mid-Atlantic Area Council, a reliability council under 202 of the Federal Power Act, established pursuant to the MAAC Agreement dated August 1, 1994, or any successor thereto.

1.23A MAAC Control Zone shall mean the aggregate of the Zones of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company and Rockland Electric Company, as shown on Schedule 14.

1.23B MAIN shall mean the Mid-America Interconnected Network, a reliability council under section 202 of the Federal Power Act established pursuant to the Amended and Restated Bylaws of MAIN dated January 8, 1998, or any successor thereof.

1.23C Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 5 of this Agreement, each Party to this Agreement also is a Member.

1.23D Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.24 NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.25 Network Resources shall have the meaning set forth in the PJM Tariff.

1.26 Network Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff.

1.27 Office of the Interconnection shall mean the employees and agents of PJM Interconnection L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Amended Operating Agreement.

1.28 Operating Agreement of PJM Interconnection, L.L.C. or **Operating Agreement** shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

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Vice President, Governmental Policy
IssuedOn: December 31, 2003

1.28A Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.28B Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the MAAC Control Zone or PJM West Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.28C Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.29 Party shall mean an entity bound by the terms of this Agreement by executing a counterpart hereof.

1.29A Peak Party Load shall be the daily summation of the weather adjusted actual coincident summer peak for the previous summer of the end-users for which the Party was responsible on that billing date, as set forth in Schedule 7 of this Agreement.

1.29B Peak Season shall have the meaning set forth in Schedule 8.

1.29C Peak Season Maintenance shall have the meaning set forth in Schedule 8.

1.29D Peak Season Maintenance Obligation shall have the meaning set forth in Schedule 8.

1.30 PJM shall mean the PJM Board and the Office of the Interconnection.

1.31 PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Amended Operating Agreement.

1.32 [Reserved.]

1.33 PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the MAAC Control Zone, the PJM West Region, and the PJM Interchange Energy Market in a manner consistent with Applicable Regional Reliability Council standards.

1.34 PJM Open Access Transmission Tariff or **PJM Tariff** shall mean the tariff for transmission service in the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.34A PJM Region shall mean the aggregate of the PJM West Region and the MAAC Control Zone.

1.35 PJM West Region shall mean the aggregate of the Zones of the West Transmission Owners.

1.35A Planning Period shall initially mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.36 Qualified Interruptible Load shall mean load (including pumped storage hydroelectric generation in the pumping mode) subject by contract to interruption by the Transmission Provider and which qualifies as Active Load Management in accordance with Schedule 5.2.

1.37 RAA shall mean the reliability assurance agreement among the load-serving entities in the MAAC Control Zone, on file with FERC as PJM Rate Schedule FERC No. 27.

1.37A [Reserved.]

1.38 [Reserved.]

1.39 [Reserved.]

1.40 Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.40A Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.41 Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

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	Vice President, Governmental Policy		
IssuedOn:	November 6, 2003		

1.41C State Consumer Advocate shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM West Region or MAAC Control Zone, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.41D Transmission Facilities shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERCs Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within such area.

1.41E Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.42 Transmission Provider shall mean PJM.

1.42A Unforced Capacity shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on a rolling 12-month average (which shall be updated each month for the 12 months ending two months prior to the billing month) without regard to the ownership of or the contractual rights to the capacity of the unit.

1.43 [Reserved.]

1.44 [Reserved.]

1.45 West Transmission Owner shall mean a Member that has executed that certain West Transmission Owners Agreement among PJM Interconnection, L.L.C. and Certain Owners of Electric Transmission Facilities. (PJM Interconnection L.L.C. Rate Schedule FERC No. 33.)

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	Vice President, Governmental Policy		
IssuedOn:	July 31, 2003		

1.46 Zone shall mean an area within the PJM West Region, as described on Schedule 14, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM West Region.

1.47 Zonal Entity shall mean the entity listed on Schedule 14 which, as a result of its present or historical load serving responsibility, is responsible under this Agreement for providing the daily load estimate of each Load Serving Entity within each Zone in the PJM West Region.

ARTICLE 2 PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources will be available to provide reliable service to loads within the PJM West Region, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM West Region. Unless this Agreement is terminated as provided in Section 4.2, every entity which is or will become a Load Serving Entity within the PJM West Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM West Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Amended Operating Agreement and PJM Tariff.

ARTICLE 3 NECESSARY PREREQUISITES

Prior to this Agreement becoming effective, each of the following events shall have occurred:

1. The Amended Operating Agreement is in full force and effect.

2. The Amended Operating Agreement shall have been executed by Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power.

3. The FERC shall have accepted the Amended Operating Agreement, this Reliability Assurance Agreement, and the PJM Tariff changes filed contemporaneously with this Agreement, including all rate changes, all without change or condition. In the event that the FERC fails to adopt, as required by this Article, all of the above agreements and Tariff changes without change or condition, the Parties hereto agree to negotiate in good faith to seek to accommodate such changes as the FERC indicates are required before acceptance. In the event of failure to so agree, no Party shall be bound by the terms of this Agreement and this Agreement shall have no further force and effect.

ARTICLE 4 TERM AND TERMINATION

4.1 Term. This Agreement shall become effective on the Effective Date and shall continue in effect until terminated in accordance with the terms hereof.

4.2 Termination.

4.2.1 Rights to Terminate. This Agreement may be terminated by a vote in the Members Committee to terminate the Agreement by an affirmative Sector Vote as specified in the Operating Agreement and upon the receipt of all Required Approvals related to the termination of this Agreement. Any such termination must be approved by the PJM Board and filed with the FERC and shall become effective only upon the FERCs approval.

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IssuedOn:	July 31, 2003		

4.2.2 Obligations upon Termination. Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination of this Agreement shall survive such termination. The surviving provisions shall include, but shall not be limited to: (a) final settlement of the obligations of each Party under Articles 9, 11, 12, and 17 of this Agreement, including the accounting for the period ending with the last day of the month for which the Agreement is effective, (b) the provisions of this Agreement necessary to conduct final billings, collections and accounting with respect to all matters arising hereunder and (c) the indemnification provisions as applicable to periods prior to such termination.

ARTICLE 5 ADDITION OF NEW PARTIES

Each Party agrees that any entity that (i) is or will become a Load Serving Entity, in the PJM West Region and (ii) complies with the process and data requirements set forth in Schedule 1, and (iii) meets the applicable standards for interconnection set forth in Schedule 2 shall become a Party to this Agreement and shall be listed in Shedule 16 of this Agreement upon becoming a Party to the Amended Operating Agreement and execution of a counterpart of this Agreement.

ARTICLE 6 WITHDRAWAL OF A PARTY

6.1 Withdrawal of a Party.

6.1.1 Notice. Upon written notice to the Office of the Interconnection, any Party may withdraw from this Agreement, effective upon the completion of its obligations hereunder and the documentation by such Party, to the satisfaction of the Office of the Interconnection, that such Party is no longer a Load Serving Entity within the PJM West Region.

6.1.2 Determination of Obligations. A Partys obligations hereunder shall be completed as of the end of the last month for which a Forecast LSE obligation (MW) has been set at the time said notice is received, except as provided in Article 14, or unless the Members Committee determines that the remaining Parties will be able to adjust their obligations and commitments related to the performance of this Agreement consistent with such earlier withdrawal date as may be requested by the withdrawing Party, without undue hardship or cost, while maintaining the reliability of the PJM West Region.

6.1.3 Survival of Obligations upon Withdrawal. (a) The obligations of a Party upon its withdrawal from the Agreement and any obligations of that Party under the Agreement at the time of its withdrawal shall survive the withdrawal of the Party from the Agreement. Upon the withdrawal of a Party from this Agreement, final settlement of the obligations of such Party under Articles 9, 11, 12, and 17 of this Agreement shall include the accounting through the date established pursuant to Sections 6.1.1 and 6.1.2.

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IssuedOn:	December 31, 2003		

(b) Any Party that withdraws from this Agreement shall pay all costs and expenses associated with additions, deletions and modifications to communication, computer, and other affected facilities and procedures, including any filing fees, to effect the withdrawal of the Party from the Agreement.

6.1.4 Regulatory Review. Any withdrawal from this Agreement shall be filed with the FERC and shall become effective only upon the FERCs approval .

6.2 Withdrawal or Breach by a Party. If a Party (a) fails to pay any amount due under this Agreement within 30 days after the due date or (b) is in breach of any material obligation under this Agreement, the Office of the Interconnection shall cause a notice of such non-payment or breach to be sent to that Party. If the Party fails, within 30 days of the receipt of such notice (except as otherwise described below), to cure such non-payment or breach, or if the breach cannot be cured within such time and if the Party does not diligently commence to cure the breach within such time and to diligently pursue such cure to completion, the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (c) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Partys license or authorization to serve retail load within the state(s) and/or (d) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys fees).

ARTICLE 7 MANAGEMENT AND ADMINISTRATION

Except as otherwise provided herein, this Agreement shall be managed and administered by the Parties, Members, and State Consumer Advocates through the Members Committee and the Reliability Committee as a Standing Committee thereof, except as delegated to the Office of the Interconnection and except that only the PJM Board shall have the authority to approve and authorize the filing of amendments to this Agreement with the FERC.

IssuedBy: Craig Glazer Effective: October 1, 2003
Vice President, Governmental Policy
IssuedOn: July 31, 2003

[Sheet Nos. 11 through 14A are reserved for future use.]

IssuedBy:	Craig Glazer	Effective:	October 1, 2003
	Vice President, Governmental Policy		
IssuedOn:	July 31, 2003		

ARTICLE 8 RESERVE REQUIREMENTS AND OBLIGATIONS

8.1 Forecast Pool Requirement and Accounted-For Obligations. (a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer who is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM West Region shall be responsible for all of that Load Serving Entitys capacity obligations under this Agreement and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM West Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entitys full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

(c) Whenever a transmission owning Party joins, or withdraws from the Amended Operating Agreement such that the boundaries of the PJM West Region are expanded or contracted, the Parties capacity obligations under this Agreement shall be re-examined by the Reliability Committee to determine whether revisions are appropriate.

8.2 Capacity Plans and Deliverability. As set forth in Schedule 6, each Party shall submit to the Office of the Interconnection its plans (or revisions to previously submitted plans) to install or contract for Capacity Resources. As set forth in Schedule 10, each Party must designate its Capacity Resources as Network Resources or Points of Receipt under the PJM Tariff to allow firm delivery of the output of its Capacity Resources to the Partys load within the PJM West Region and each Party must obtain any necessary Firm Transmission Service in an amount sufficient to deliver Capacity Resources from outside of the PJM Region to the border of the PJM Region to reliably serve the Partys load within the PJM West Region.

8.3 Responsibility to Provide Unforced Capacity. (a) Each Party shall install or contract for Capacity Resources or obtain Capacity Credits providing Unforced Capacity sufficient to satisfy each day its Accounted-For Obligation, as determined pursuant to Schedule 7.

(b) A Party that fails to satisfy its obligations to provide sufficient Unforced Capacity shall be deficient and shall pay the applicable deficiency charge determined pursuant to Schedule 11.

8.4 Responsibility During Peak Season. (a) Each Party shall install or contract for Capacity Resources or obtain Capacity Credits providing Unforced Capacity during the Peak Season sufficient to satisfy the sum of its Accounted-For Obligation and its Peak Season Maintenance Obligation.

(b) A Party that fails to have Unforced Capacity on any day during the Peak Season adequate to satisfy the sum of its Accounted-For Obligation and its Peak Season Maintenance Obligation shall be considered to be deficient to the extent set forth in Schedule 8.

8.4A Prohibition of Sales. (a) The Office of the Interconnection shall determine each partys daily Accounted For Obligation pursuant to Schedule 7 at noon two business days before the day for which the Accounted For Obligation is being determined, in the case of that portion of a Partys Accounted For Obligation that is in a Zone that has adopted a retail access program for end-use electric customers.

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	Vice President, Governmental Policy		
IssuedOn:	April 1, 2003		

(b) No party may sell capacity or Capacity Credits for any day for which its Accounted For Obligation has been determined unless it has capacity or Capacity Credits available to sell in excess of its Accounted For Obligation plus its other contractual obligations to sell capacity.

8.4B Nature of Resources. (a) Each Party shall provide or arrange for specific, firm Capacity Resources that are capable of supplying the energy requirements of its own load on a firm basis without interruption for economic conditions and with such other characteristics that are necessary to support the reliable operation of the PJM West Region, as set forth in more detail in Schedules 9 and 10.

(b) The Parties agree that Capacity Credits may be relied upon by a Party to satisfy its obligations to provide and arrange for Capacity Resources.

IssuedBy: Craig Glazer
Vice President, Governmental Policy
IssuedOn: July 31, 2003

Effective: October 1, 2003

8.5 Compliance Audit of Parties. (a) For the 36 months following the end of each Planning Period, each Party shall make available the records and supporting information related to the performance of this Agreement from such Planning Period for audit.

(b) The Office of the Interconnection shall evaluate and determine the need for an audit of a Party, and shall, upon a decision of the Office of the Interconnection to require such an audit, provide the Party or Parties to be audited with notice at least 90 days in advance of the audit.

(c) Any audit of a Party conducted pursuant to this Agreement shall be performed by an independent consultant to be selected by the Office of the Interconnection. Such audit shall be limited to a review of the Partys compliance with the requirements of this Agreement.

(d) Prior to the completion of its audit, the independent consultant shall review its preliminary findings with the Party being audited and, upon the completion of its audit, the independent consultant shall issue a final audit report detailing the results of the audit, which final report shall be issued to the Party being audited, the Office of the Interconnection and the Members Committee; provided, however, no confidential data of any Party shall be disclosed through such audit reports.

(e) If, based on a final audit report, an adjustment is required to any amounts due to or from the Parties pursuant to Schedule 11, such adjustment shall be accounted for in determining the amounts due to or from the Parties pursuant to Schedule 11 for the month in which the adjustment is identified.

8.6 Interim Capacity Obligations in the ComEd Zone. Notwithstanding the above provisions of this Article 8, the obligations of Parties serving load in the ComEd Zone during the Interim Period, as those terms are defined in Schedule 17, shall be determined as set forth in Schedule 17.

ARTICLE 9 DEFICIENCY AND EMERGENCY CHARGES

9.1 Nature of Charges. Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement. Such charges are set forth in Schedules 11 and 12.

9.2 Determination of Charge Amounts. No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement for the next June 1 to May 31 twelve-month period, and Schedules 11 and 12, which, upon approval of the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Reliability Committee may establish projected charges for estimating purposes only.

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IssuedOn:	July 31, 2003		

9.3 Distribution of Charge Receipts. All of the monies received as a result of any charges imposed pursuant to this Agreement and Section 5.6 of Schedule 11 of the Amended Operating Agreement shall be disbursed as provided in Schedules 11 and 12 of this Agreement.

9.4 Charges Relating to Interim Capacity Obligations in the ComEd Zone. Notwithstanding the above provisions of this Article 9, any charges related to the obligations of Parties serving load in the ComEd Zone during the Interim Period, as those terms are defined in Schedule 17, shall be determined as set forth in Schedule 17.

ARTICLE 10 COORDINATED PLANNING AND OPERATION

10.1 Overall Coordination. Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with Applicable Regional Reliability Council and NERC regional practices. In furtherance of such Cooperation each Party shall:

(a) coordinate its Capacity Resource plans with the other Parties to maintain reliable service to its own electric customers and those of the other Parties;

(b) cooperate with the members and associate members of MAAC, ECAR, MAIN, and NERC to ensure the reliability of the region;

(c) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM West Region in accordance with the Amended Operating Agreement;

(d) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(e) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(f) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies;

(g) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection; and

(h) meet its obligations under the Amended Operating Agreement.

10.2 Generator Planned Outage Scheduling. Each Party shall develop or, to the maximum extent its legal rights will allow, cause to be developed, schedules of planned outages of its Capacity Resources. Such schedules of planned outages shall be submitted to the Office of the Interconnection for coordination with the schedules of planned outages of other Parties and anticipated transmission planned outages.

10.3 Data Submissions. Each Party shall submit to the Office of the Interconnection for review, any data and other information necessary for the performance of this Agreement, including its plans for the addition, modification and removal of Capacity Resources, its load forecasts, and such other data set forth in Schedule 15.

10.4 Charges for Failures to Comply. An emergency procedure charge, as set forth in Schedule 12, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection pursuant to any capacity resource plan on file with the Office of Interconnection under Schedule 6.

10.5 Metering. Each Party shall comply with the metering standards as set forth in the PJM Manuals.

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Vice President, Governmental Policy
IssuedOn: December 31, 2003

ARTICLE 11 SHARED COSTS

11.1 Recording and Audit of Costs.

(a) Any costs related to the performance of this Agreement, including the costs of the Office of the Interconnection and such other costs that the Members Committee determines are to be shared by the Parties, shall be documented and recorded in a manner acceptable to the Parties.

(b) The Members Committee may require an audit of such costs; provided, however, the cost records shall be available for audit by any Member or State Consumer Advocate, at the sole expense of such Member or State Consumer Advocate, for 36 months following the end of the Planning Period in which the costs were incurred.

11.2 Cost Responsibility. The costs determined under Section 11.1(a) shall be allocated to and recovered from the Parties to this Agreement and other entities pursuant to Schedule 9-5 of the PJM Tariff.

ARTICLE 12 BILLING AND PAYMENT

12.1 Periodic Billing. Each Party shall receive a statement periodically setting forth (i) any amounts due from or to that Party as a result of any charges imposed pursuant to this Agreement and (ii) that Partys share of any costs allocated to that Party pursuant to Article 11. To the extent practical, such statements are to be coordinated with any billings or statements required pursuant to the Amended Operating Agreement or PJM Tariff.

12.2 Payment. The payment terms and conditions shall be as set forth in the billing statement and shall, to the extent practicable, be the same as those then in effect under the PJM Tariff.

12.3 Failure to Pay. If any Party fails to pay its share of the costs allocated pursuant to Article 11, those unpaid costs shall be allocated to and paid by the other Parties hereto in proportion to the sum of the Accounted For Obligations of each such Party (calculated without any reduction for ALM load credit) for the billing month. The Office of the Interconnection shall enforce collection of a Partys share of the costs.

ARTICLE 13 INDEMNIFICATION AND LIMITATION OF LIABILITIES

13.1 Indemnification. (a) Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents for all actions, claims, demands, costs, damages and liabilities asserted by third parties against the Party seeking indemnification and arising out of or relating to acts or omissions in connection with this Agreement of the Party from which indemnification is sought, except (i) to the extent that such liabilities result from the willful misconduct of the Party seeking indemnification and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmens compensation law. Nothing herein shall limit a Partys indemnity obligations under Article 16 of the Amended Operating Agreement.

(b) The amount of any indemnity payment under this Section 13.1 shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified actions, claims, demands, costs, damages or liabilities. If any Party shall have received an indemnity payment in respect of an indemnified action, claim, demand, cost, damage, or liability and shall subsequently actually receive insurance proceeds or other amounts in respect of such action, claim, demand, cost, damage, or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

13.2 Limitations on Liability. No Party will be liable to another Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party including, but not limited to, loss of profits or revenues, cost of capital or financing, loss of goodwill and cost of replacement power arising from such Partys carrying out, or failure to carry out, any obligations contemplated by this Agreement; provided, however, nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a party to this Agreement.

13.3 Insurance. Each Party shall obtain and maintain in force such insurance as is required of Load Serving Entities by the states in which it is doing business within the PJM West Region.

ARTICLE 14 SUCCESSORS AND ASSIGNS

14.1 Binding Rights and Obligations. The rights and obligations created by this Agreement and all Schedules and supplements thereto shall inure to and bind the successors and assigns of the Parties; provided, however, no Party may assign its rights or obligations under this Agreement without the written consent of the Members Committee unless the assignee concurrently becomes the Load Serving Entity with regard to the end-users previously served by the assignor.

14.2 Consequences of Assignment. Upon the assignment of all of its rights and obligations hereunder to a successor consistent with the provisions of Section 14.1, the assignor shall be deemed to have withdrawn from this Agreement.

ARTICLE 15 NOTICE

Except as otherwise expressly provided herein, any notice required hereunder shall be in writing and shall be sent: overnight courier, hand delivery, telecopy or other reliable electronic means to the representative on the Members Committee of such Party at the address for such Party previously provided by such Party to the other Parties. Any notice shall be deemed to have been given (i) upon delivery if given by overnight courier, hand delivery or certified mail or (ii) upon confirmation if given by facsimile or other reliable electronic means.

ARTICLE 16 REPRESENTATIONS AND WARRANTIES

16.1 Representations and Warranties at Date an Entity Becomes a Party. Each Party represents and warrants to the other Parties that, as of the date it becomes a Party:

(a) the Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

(b) the execution and delivery by the Party of this Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict with any applicable law or with any other agreement binding upon the Party. The Agreement has been duly executed and delivered by the Party, and this Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditors rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

(c) there are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder.

16.2 Continuing Representations and Warranties. Each Party represents and warrants to the other Parties that throughout the term of this Agreement:

(a) the Party is a Load Serving Entity;

(b) the Party satisfies the requirements of Schedule 2;

(c) the Party is in compliance with the Reliability Principles and Standards;

(d) the Party is a signatory, or its principals are signatories, to the agreements set forth in Schedule 3;

(e) the Party is in good standing in the jurisdiction where incorporated; and

(f) the Party will endeavor in good faith to obtain any corporate or regulatory authority necessary to allow the Party to fulfill its obligations hereunder.

ARTICLE 17 OTHER MATTERS

17.1 Relationship of the Parties. This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation or partnership liability upon any Party.

IssuedBy: Craig Glazer Effective: June 1, 2003
Vice President, Governmental Policy
IssuedOn: April 1, 2003

17.2 Governing Law. This Agreement shall be interpreted, construed and governed by the laws of the State of Delaware.

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	Vice President, Governmental Policy		
IssuedOn:	April 1, 2003		

17.3 Severability. Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

17.4 Amendment. This Agreement may be amended only by action of the PJM Board. Notwithstanding the foregoing, an applicant eligible to become a Party in accordance with the procedures set forth in Schedule 1 shall become a Party by executing a counterpart of this Agreement without the need for execution of such counterpart by any other Party. The Office of the Interconnection shall file with FERC any amendment to this Agreement approved by the PJM Board.

17.5 Headings. The article and section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

17.6 Confidentiality. (a) No Party shall have a right hereunder to receive or review any documents, data or other information of another Party, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection or to the extent that they have been designated as confidential by another Party; provided, however, a Party may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite document does not disclose any individual Partys confidential data or information.

(b) Notwithstanding anything in this Section to the contrary, if a Party is required by applicable laws, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, that Party may make disclosure of such information; provided, however, that as soon as the Party learns of the disclosure requirement and prior to making disclosure, that Party shall notify the affected Party or Parties of the requirement and the terms thereof and the affected Party or Parties may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement and the Party shall cooperate with such affected Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(c) Any contract with a contractor retained to provide technical support or to otherwise assist with the administration of this Agreement shall impose on that contractor a contractual duty of confidentiality that is consistent with this Section.

17.7 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

17.8 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Partys right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

17.9 No Third Party Beneficiaries. This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party not a signatory hereto.

17.10 Dispute Resolution. Except as otherwise specifically provided in the Amended Operating Agreement, disputes arising under this Agreement shall be subject to the dispute resolution provisions of the Amended Operating Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

PJM INTERCONNECTION, L. L. C.

Date: By: /s/ Phillip G. Harris
Title President and Chief Executive Officer

AMERICAN ELECTRIC POWER SERVICE CORPORATION

Date: By: /s/ J. Craig Baker

Title Senior Vice President - Regulatoroy Services

SCHEDULE 1

PROCEDURES TO BECOME A PARTY

A. Notice

Any entity that is or will become a Load Serving Entity within the PJM West Region and thus a Party to this Agreement shall submit a notice to the Office of the Interconnection together with (i) its representation that it has satisfied or will (prior to the date this Agreement is to become effective as to that entity) satisfy the requirements to become a Party, and (ii) a deposit in an amount to be specified that will be applied toward the costs of any required analysis.

The required notice, representations, data and deposit must be submitted in sufficient time to conduct an analysis of the data submitted and to adjust the obligations of the Parties for the month in which the entity desires to become a Party:

> If the then existing boundaries of the PJM Region would be expanded by an entity becoming a Party, that entity shall submit the required notice, representation, data and deposit no later than when the entity applies for its transmission facilities to be included in the PJM Tariff.

> If an entity will serve load within the then existing boundaries of the PJM Region, that entity shall submit the required notice, representations, data and deposit as soon as possible prior to the month (i) in which it is to begin serving loads within the PJM West Region or (ii) in which any agency relationship through which the entitys obligations under this Agreement had been satisfied is terminated; provided, however, that such submission shall not be required sooner than any request for transmission service or any change in the designation of Network Resources or points of receipt and loads under the PJM Open Access Tariff associated with providing service to those loads.

B. Analysis of Data

The notice, representations and data submitted to the Office of the Interconnection are to be analyzed in accordance with procedures consistent with this Agreement and the encouragement of reliable operation of the PJM West Region.

C. Response

Upon completion of the analysis, the Office of the Interconnection will inform the entity of (a) the estimated costs and expenses associated with modifications to communication, computer and other facilities and procedures, including any filing fees, needed to include the entity as a Party, (b) the entitys share of any costs pursuant to Article 11, and (c) the earliest date upon which the entity could become a Party. In addition, a counterpart of the Agreement shall be forwarded for execution.

Vice President, Governmental Policy
IssuedOn: July 29, 2003
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER03-703-000, issued May 30, 2003, 103 FERC 61,250.

D. Agreement by New Party

After receipt of the response from the Office of the Interconnection, the entity shall identify its representative to the Members Committee and Reliability Committee execute the counterpart of the Agreement, indicating the desired effective date; provided, however, such effective date shall be the first day of a month, may be no earlier than the date indicated in the response from the Office of the Interconnection and shall be no later than (i) the date on which the entity begins serving loads within the PJM West Region or (ii) the termination date of any agency relationship through which its obligations under this Agreement had been satisfied. The executed counterpart of the Agreement, together with payment of its share of any costs then due, shall be returned as directed by the Office of the Interconnection.

IssuedBy:	Craig Glazer Vice President, Governmental Policy	Effective:	October 1, 2003
IssuedOn:	July 31, 2003		

SCHEDULE 2

STANDARDS FOR INTEGRATING AN ENTITY INTO THE PJM REGION

A. The following standards will be applied by the Office of the Interconnection to determine the eligibility of an entity to become a part of the PJM Region. For an entity to be integrated into the PJM Region it must possess generation and transmission attributes that would enable the entity to share its reserves with other entities in the PJM Region. Appropriate transmission and reliability studies are to be performed to determine the adequate transmission capability necessary to integrate the entity into the PJM Region consistent with Good Utility Practice.

B. In addition, the entity shall meet the following requirements to be included in the PJM Region:

1. All load, generation and transmission operating as part of the PJM Regions interconnected system must be included within the metered boundaries of the PJM Region.

2. The entity will accept and comply with the PJM Regions standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region.

3. The load, generation and transmission facilities of each entity shall be included in the telemetry to the Office of the Interconnection from a 24-hour control center. Each system operator in these control centers must be trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner.

4. Each entity must have compatible operational communication mechanisms, maintained at its expense, to interact with the Office of the Interconnection and for internal requirements.

5. Each entity must assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the Office of the Interconnection as it directs the operation of the PJM Region.

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IssuedOn:	April 1, 2003		

SCHEDULE 3

OTHER AGREEMENTS TO BE EXECUTED BY THE PARTIES

Any agreement for Network Transmission Service or Firm Point-To-Point Service that is required under the PJM Tariff for service consistent with the requirements of Section 10.1(c);

The Amended Operating Agreement.

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IssuedOn:	April 1, 2003		

[Sheet Nos. 27-29 are reserved.]

IssuedBy:	Craig Glazer	Effective:	June 1,2003
	Vice President, Governmental Policy		
IssuedOn:	April 1, 2003		

SCHEDULE 4

GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT

A. Objective Of The Forecast Pool Requirement

The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources and ALM that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.

B. Forecast Pool Requirement To Be Determined Annually

Eleven months in advance of each Planning Period based on the projections described in section C of this Schedule, the PJM Board, acting upon the recommendation of the Members Committee, shall establish the Forecast Pool Requirements for the Parties for such Planning Period annually before June 30. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement for such Planning Period shall be considered firm and not subject to re-determination thereafter; provided, however, that the Forecast Pool Requirement (including the ALM Factor and the installed reserve margin) shall be revised, to the extent determined necessary by the PJM Board, to reflect the addition of a new transmission owner zone to the PJM Region, with such revision to be effective on the first day of the first Interval that is at least three months after the date of such addition; and provided further that in such cases the PJM Board may in its discretion direct that the revised Forecast Pool Requirement (including the ALM Factor and the installed reserve margin) may be implemented in the added transmission owner zone effective upon the date of its integration into the PJM Region, notwithstanding that such revised Forecast Pool Requirement otherwise shall take effect in the remainder of the PJM Region at a later time in accordance with the foregoing proviso.

C. <u>Methodology</u>

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in Schedule 15, the Amended Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirements shall consider the following data and forecasts as necessary.

Seasonal peak load forecasts for each Planning Period as provided by each Party reflecting (a) load forecasts with a 50 percent probability of being too high or too low, (b) summer peak diversities determined by the Office of the Interconnection from recent experience and (c) ALM as determined pursuant to Schedule 5.2 and in accordance with the PJM Manuals.

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2. Forecasts of aggregate seasonal load shape of the Parties which are consistent with forecast averages of 52 weekly peak loads prepared by the Parties and obtained from Electric Distributors for their respective systems.

3. Variability of loads within each week, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

4. Generating unit capability and types for every existing and proposed unit.

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Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

Generator Maintenance Outage factors and planned outage schedules as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

Miscellaneous adjustments to capacity due to all causes, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

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SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

Based on the guidelines set forth in Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

A. The installed capacity requirement (ICR) shall be determined as:

$$ICR = (FAP - FALC) * (1 + IRM)$$

Where:

= the forecast accounting peak for the PJM Region, which shall be the weather-normalized, 50/50 probability load prior to ALM being invoked

= the forecast of the ALM credit adjustment for the PJM Region

= the installed reserve margin approved by the PJM Board, upon the recommendation of the Reliability Committee, for that Planning Period

B. The PJM Region equivalent demand forced outage rate (EFORD) shall be determined as the capacity weighted EFORD for all units expected to serve loads within the PJM Region as determined pursuant to Schedule 5.1.

C. The PJM Region unforced capacity requirement (UCR) shall be determined as:

$UCR = ICR * (1 - EFOR_D)$.

D. The PJM Region Forecast Pool Requirement (FPR) in percent shall be determined as:

$FPR = [UCR/(FAP-FALC)] * 100$.

Vice President, Governmental Policy

IssuedOn: November 6, 2003

SCHEDULE 5

DETERMINATION OF FORECAST REQUIREMENTS AND OBLIGATIONS

A. Each Party shall be responsible for satisfying the Forecast Pool Requirement related to the end-users it serves.

B. It is recognized that changing conditions and improvements in techniques may require from time to time modifications to the determination of obligations hereunder. A Party or the Office of the Interconnection having the opinion that such a modification is required shall request the Members Committee to have the matter studied and a recommendation made to the PJM Board. Upon approval of a change by the PJM Board, this schedule and other related schedules shall be appropriately revised and supplemented and shall thereupon be made effective.

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IssuedOn:	July 31, 2003		

SCHEDULE 5.1

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ($EFOR_D$) shall be calculated as follows:

$$EFOR_D(\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

Where

f_f = full outage factor

f_p = partial outage factor

FOH = full forced outage hours

EFPOH = equivalent forced partial outage hours

SH = service hours

B. Calculation of average $EFOR_D$ for Forecast Unforced Capacity Requirements and Obligations

The forecast average $EFOR_D$ in a Planning Period shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Capacity Resources of the Parties serving load within the PJM Region that are planned to be in service including Capacity Resources purchased from specified units and excluding Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Reliability Committee to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region. All rates shall be in percent.

The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices approved by the Reliability Committee.

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The EFORD of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar

Years

One fifths the rate experienced during the calendar year, plus four-fifths the class average rate.

Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.

Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.

Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

C. Calculations of average $EFOR_D$ for Accounted-For Obligations for Unforced Capacity

The average $EFOR_D$ used to determine a Load Serving Entitys ability to meet its Accounted-For Obligation for Unforced Capacity in a month shall be the average of the forced outage rates, weighted for unit capability, calculated on a twelve-month rolling average basis for the twelve-month period ending two months prior to the first month of the Interval for which the obligation was incurred, attributable to all of the generating units of the Load Serving Entity committed to serve load within the Zone. These resources include Capacity Resources purchased from specified units and exclude Capacity Resources sold from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustment approved by the Members Committee to adjust the parameters of a designated unit.

The EFOR $_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve most recent calendar months, allowing for up to a two month period to collect data and calculate rates. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

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The $EFOR_D$ of a unit in service at least one full calendar month but less than twelve full calendar months prior to the calculation month shall be the average of the actual $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by twelve minus months of service, allowing for up to a two-month period to collect data and calculate rates. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

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SCHEDULE 5.2

PROCEDURES FOR THE

ACTIVE LOAD MANAGEMENT CREDIT

A. Parties can receive an adjustment to their load used in determining their Accounted-For Obligation for ALM that is operated under the direction of the Office of the Interconnection. For a Party to receive this adjustment to load, ALM must satisfy the following criteria:

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and paragraph E of this schedule as applicable, the Office of the Interconnection of the ALM that it is placing under the direction of the Office of the Interconnection.

2. The initiation of load interruption, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

3. A period of no more than 2 hours prior notification must apply to interruptible customers.

4. The initiation of ALM upon the request of the Office of the Interconnection is considered an emergency action and must be implementable prior to a voltage reduction.

5. A Party must agree to reserve, for interruption at the direction of the Office of the Interconnection, at least 10 interruptions per Planning Period in order to receive ALM credit.

6. A Party must agree to reserve interruptions of at least 6-hour duration. As a minimum, such 6-hour duration for interruptions should be available on weekdays during the 8-hour daily peak window for the appropriate season. There will be no credit given to Parties who choose to provide interruption less than 6 hours and/or exclusive of the above time period.

·The ALM must be available during the summer period of June through September for credit in the corresponding Planning ·Period.

B. The ALM load credit of a Party will be determined as:

The ALM load credit of a Party will be the product of the nominal megawatt value of that Partys ALM multiplied by the ALM Factor. The ALM Factor is a factor established by the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to ALM for the PJM Region divided by the total nominal amount of ALM in the PJM Region. The PJM ALM Factor will be determined

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using an analytical program that uses a probabilistic approach to determine reliability. The determination of the PJM ALM Factor will consider the reliability of the active load management, the number of interruptions, and the total amount of active load management. The detailed procedures used for calculating the PJM ALM Factor shall be set forth in the PJM Manuals.

The ALM credit value for the individual Parties shall be calculated as follows:

ALM credit = Megawatt Value of a Partys ALM x PJM ALM Factor

C. The Electric Distributor or LSE that establishes a contractual relationship (by contract or tariff rate) with a customer for ALM reductions is entitled to the PJM ALM credit for the customer, regardless of the customers energy supplier.

D. The Parties need to demonstrate that their ALM performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of ALM.

E. Prior to the commencement of the Planning Period, Parties may elect to place ALM associated with Behind The Meter Generation under the direction of the Office of the Interconnection. This election shall remain in effect for the entire Planning Period. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating Accounted-For Obligations under this Agreement.

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SCHEDULE 6

PLANS TO MEET CAPACITY OBLIGATIONS

A. Each Party shall submit to the Office of the Interconnection its plans for satisfying its estimated Accounted-For Obligation through Capacity Resources, including (1) installation of generating resources or (2) purchases.

Each Party must submit to the Office of the Interconnection a notice of any change in its plans for Capacity Resources three months (or such shorter time period consistent with the ability of the Office of the Interconnection to evaluate requests for Network Transmission Service, the designation of Network Resources or the identification of a Point of Receipt for Firm Point-to-Point Service) prior to each month in a Planning Period.

B. The Capacity Resource plans of each Party shall indicate the nature and current status of commitments with respect to each addition, retirement and sale or purchase of capacity included in its plans. The Office of the Interconnection will review the adequacy of the submittals hereunder both as to timing and content.

C. The specific Capacity Resources identified in a Partys plans may be adjusted at any time; provided, however, no such adjustment may be retroactive and any new Capacity Resource must also be a Network Resource or Point of Receipt deliverable to loads on a firm basis under the PJM Tariff.

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[Sheet No. 33 is reserved.]

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SCHEDULE 7

DETERMINATION OF ACCOUNTED-FOR OBLIGATION

AND DEFICIENCIES

A. Each Partys Accounted-For Obligation shall be determined pursuant to the provisions of this Schedule.

:For each billing month during a Planning Period the Accounted-For Obligation of a Party shall be determined on a daily basis as .follows:

Accounted-For Obligation = (FSP ALM credit) x FPR/100

Where:

FSP=	the daily summation of the forecasted weather-adjusted coincident summer peak of the end-users in the PJM Region (net of operating Behind The Meter Generation, but not to be less than zero) for which the Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals
ALMcredit=	the ALM load adjustments to the Party for the Zone determined pursuant to Schedule 5.2
FPR=	the Forecast Pool Requirement

:A Party shall be deficient and shall pay the deficiency charge set forth in Schedule 11 if the Partys Unforced Capacity is less .than its Accounted-For Obligation. Such deficiencies shall be measured on a day-by-day basis as required by changes in a Partys Unforced Capacity and in its responsibilities for service to end-users.

B. For purposes of determining deficiencies pursuant to paragraph A.2 of this Schedule, the sum of the Unforced Capacity for each Capacity Resource and the Capacity Credits relied on by a Party shall be established by the Office of the Interconnection on a daily basis, subject only to adjustment for the transfer of rights to Capacity Resources (including the purchase or sale of Capacity Credits) during a period in the initial billing month (as defined in the PJM Manuals) in which the final Accounted-For Obligation of a Party is known; provided, however, that such transfers of rights to Capacity Resources shall (1) include only resources that qualify as Capacity Resources on the day a Party intends to rely on the Unforced Capacity of those Capacity Resources to satisfy its Accounted-For Obligation and (2) exclude any Firm Transmission Rights, as that term is defined under the Operating Agreement. Notwithstanding anything to the contrary herein, the Capacity Credits held by a Party shall be counted fully toward the satisfaction of that Partys Accounted-For Obligation.

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SCHEDULE 8

PEAK SEASON MAINTENANCE

A. To preserve and maintain the reliability of the PJM Region and to recognize the impact of planned outages and maintenance outages during the Peak Season, each Party is obligated to have sufficient Unforced Capacity to satisfy its Accounted-For Obligation plus its Peak Season Maintenance Obligation during the Peak Season.

B. The Peak Season shall be defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

C. Peak Season Maintenance is defined as planned outages and maintenance outages during the Peak Season.

D. For each day during the Peak Season, the Peak Season Maintenance Obligation of a Party shall be the amount, in megawatts, which shall be based on the Unforced Capacity of the Unit, of that Partys Peak Season Maintenance at the time of the PJM Region daily peak, excluding outages for maintenance when released by the Office of the Interconnection for a specified period and other outages as approved by the Reliability Committee from time to time.

E. A Party shall be deficient and shall pay the charge set forth in Schedule 11 it its Unforced Capacity is less than the sum of its Peak Season Maintenance Obligation and its Accounted-For Obligation (as determined pursuant to Schedule 7); provided, however, that Party shall be considered to be deficient only to the extent of any megawatts of deficiency in excess of the number of megawatts for which such Party already has paid a deficiency charge related to Schedule 7.

F. The Office of the Interconnection may, in accordance with the Amended Operating Agreement and the PJM Manuals, withdraw its approval of a Generator Planned Outage in connection with anticipated implementation or avoidance of Emergency procedures. If this delay in the start of a Generator Planned Outage causes the end of such outage (based on its planned duration at the time of the delay) to be in the Peak Season, there will be no requirement for additional Capacity Resources for the number of Peak Season days equal to the number of days of delay in the start of the Generator Planned Outage.

G. Subject to the provisions of Section 10.2 of the Agreement, the Office of the Interconnection shall adopt and maintain rules and procedures for determining the allowable Peak Season Maintenance.

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SCHEDULE 9

PROCEDURES FOR

ESTABLISHING THE CAPABILITY OF CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Capacity Resources for the purposes of meeting a Load Serving Entitys obligation under the Agreement shall be approved by the Reliability Committee and maintained in the PJM Manuals.

B. The rules and procedures for determining and demonstrating the capability of generating units to serve load in the PJM Region shall be consistent with achieving uniformity for planning, operating, accounting and reporting purposes.

C. The rules and procedure shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies.

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SCHEDULE 10

PROCEDURES FOR ESTABLISHING

DELIVERABILITY OF CAPACITY RESOURCES

Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Region that may have a capacity deficiency at any time. Deliverability shall be demonstrated by either obtaining or providing for Network Transmission Service or Firm Point-To-Point Transmission Service within the PJM Region such that each Capacity Resource is either a Network Resource or a Point of Receipt, respectively. In addition, for Capacity Resources located outside the metered boundaries of the PJM Region that are used to meet an Accounted-For Obligation, the capacity and energy of such Capacity Resources must be delivered to the metered boundaries of the PJM Region through firm transmission service.

Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide that service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Capacity Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service or Firm Point-To-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

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SCHEDULE 11

DEFICIENCY CHARGES

A. Deficiency Rate

The rate for deficiencies determined pursuant to Schedules 7 and 8 shall be approved annually by the Reliability Committee based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. The annual carrying charges shall be divided by a factor of one less the forecast average $EFOR_D$ for the most recent calendar year (as determined pursuant to Schedule 5.1) to state the rate in terms of Unforced Capacity. Until otherwise changed by the Reliability Committee, the rate for deficiencies shall be $160 per megawatt-day ($58.40 per kilowatt-year) divided by a factor of one less the average $EFOR_D$.

B. Calculation of Deficiency Charges for Schedule 7

The deficiency charge for a deficiency determined pursuant to Schedule 7 shall be calculated in a manner set forth herein:

DC = (R x L)

Where:

DCis the daily deficiency charge in dollars.

Ris the daily deficiency rate in dollars per megawatt-day in terms of Unforced Capacity as defined in section A.

Lis the deficiency calculated pursuant to section C of Schedule 7.

A change in Accounted-For Obligation due to an increase in customers during the applicable Interval shall be determined by subtracting the Party Peak Load of the Party (net of its operating Behind The Meter Generation, but not to be less than zero) on the twentieth day of the immediately preceding month from the Party Peak Load (net of its operating Behind The Meter Generation, but not to be less than zero) on the day the Party is deficient and multiplying this quantity by the Forecast Pool Requirement. If that number is positive, then the Party shall be assessed the DC for that portion of its deficiency due to such increase in customers.

If, on any day during an Interval, all or part of a deficiency occurs for reasons other than an increase in a Partys Accounted-For Obligation due to an increase in customers as defined in subsection 2, above, then an entity shall pay the Interval Deficiency Charge per MW of deficiency. The Interval Deficiency Charge shall be paid only once during an Interval and shall be based on the largest amount of megawatts a Party is deficient on any one day during the Interval.

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C. Calculation of Deficiency Charges for Schedule 8

The deficiency charge for deficiencies determined pursuant to Schedule 8 shall be DC

= (R x P), where the meanings of DC and R are as set forth above and P means the deficiency determined pursuant to section E of Schedule 8.

D. Distribution Of Deficiency Charges

i. Recipients of capacity deficiency revenues are defined for each Interval as: (a) each owner of Capacity Resources with Unforced Capacity which it has committed to PJM prior to the start of the Interval for every day of the Interval; (b) each owner of newly certified Capacity Resources that become available during an Interval and which are committed to PJM for every remaining day of the Interval after such certification; and (c) each Party and each party to the RAA that has fully satisfied its obligation on every day during the Interval for which a deficiency charge has been established pursuant to this Agreement. Recipients shall share in any deficiency charges paid by any Party or by any party to the RAA during the Interval that has failed to satisfy its obligation and that have been received by the Office of the Interconnection, in accordance with subsection (ii) below.

ii. A Recipient shall receive the higher of (a) a proportionate share of the deficiency charges for the Interval equal to ((x+ y)/z); or (b) the alternate value of capacity times y. Except that, if, for an owner of Capacity Resources, the Alternate Value of capacity multiplied by (y) is greater than [(y) divided by (z)] times the total deficiency charges, then: (1) each owner of Capacity Resources with net capacity shall receive the Alternate Value of capacity multiplied by (y), provided, however, that if the sum of the payments thus calculated exceeds the total deficiency charges collected, each Capacity Resource owner will receive a proportional share of the total deficiency charges equal to (y) divided by the sum (y), times the total deficiency charges; and then (2) any remaining deficiency charges shall be allocated to each LSE that has fully satisfied its Accounted-For Obligation, where the share of each such LSE shall be (x) divided by the total of (x) for all LSEs.

Where:

x is the average MW of covered obligation for a Party for every day of the Interval.

y is (a) the minimum MW of capacity, uncommitted to any LSE and committed and available to PJM prior to the start of the interval, if committed by a capacity owner for every day of the entire Interval, or (b) the minimum MW of capacity, uncommitted to any LSE and committed and available to PJM from a new

resource, if committed by a capacity owner for every remaining day of the Interval after the capacity becomes available multiplied by the ratio of the remaining days to the total days in the Interval.

z is the total of x and y for all Recipients

A Recipient that commits the Unforced Capacity of a Capacity Resource to PJM for an Interval must commit the Capacity Resource for the entire duration of the Interval. A Party that commits the Unforced Capacity of a new Capacity Resource to PJM for the balance of an Interval must commit the Capacity Resources for the entire duration of the balance of the Interval.

i for purposes of this Section D only, the alternate value of capacity (AV) shall be defined as:
i
i
.

AV = F*16*OD

Where:

F equals (Average of the Forward Market Monthly On-Peak Energy Prices over the Interval for Cinergy Hub) minus (Average of the Forward Market Monthly On-Peak Energy Prices over the Interval for PJM West Hub)

16 is the number of on-peak hours per day

OD is the number of On-Peak Days in the Interval

This value will be determined for the five on-peak days (as defined in Schedules 7 and 8 of the PJM Open Access Transmission Tariff) preceding the 15 th day of the month immediately prior to the beginning of an Interval. The forward prices used in the AV calculation shall be the weighted average of the prices published, on the identified day, in such trade publication(s) as are approved by the Reliability Committee and which shall be posted on the PJM web site. If no new index is determined prior to the beginning of an Interval the current index will be continued.

iIn the event all of the Parties and all of the parties to the RAA have incurred deficiency charges with respect to an obligation and there is no owner of Capacity Resources entitled to payments as described above, the deficiency charges shall be distributed as .approved by the Reliability Committee.

E. ALM Deficiency Charge

1. Each Party that specifies ALM pursuant to Schedule 5.2 but, in an Emergency, does not deliver, upon the request of the Office of the Interconnection, its entire specified amount of ALM will be assessed a deficiency charge in accordance with the following formula:

Compliance Deficiency Value x Daily Capacity Deficiency Rate x 365/10

Where:

Compliance Deficiency Value is equal to the amount of ALM (in megawatts) a Party is deficient, if, during an Emergency, the Party, upon the request of the Office of the Interconnection, provides less ALM than it specified pursuant to Schedule 5.2;

Daily Capacity Deficiency Rate is the rate specified in Paragraph A of this Schedule 11.

2. Revenues from deficiency charges will be distributed to the Parties and to the parties to the RAA that, during an Emergency, provide ALM in excess of the amount they specified pursuant to Schedule 5.2 of the agreement to which it is a party (prorated if necessary). Any deficiency charge payment not so distributed will be distributed at the discretion of the Reliability Committee.

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SCHEDULE 12

EMERGENCY PROCEDURE CHARGES

A. Emergency Procedure Charges

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as recommended by the Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge as follows: for each megawatt ALM that was not interrupted as directed and for each megawatt of a Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM Region in the case of a Capacity Resource located outside of the PJM Region, the Party shall pay 365 times the daily deficiency rate per megawatt set forth in Section A of Schedule 11.

B. Distribution Of Emergency Procedure Charges

1. Each Party and each party to the RAA that has complied with the emergency procedures imposed by this Agreement or the RAA during an Emergency, without incurring an emergency procedure charge, shall share in any emergency procedure charges paid by any other Party or by any party to the RAA that has failed to satisfy said obligation during an Emergency. Such shares shall be in proportion to the sum of the Accounted For Obligations (calculated without any reduction for ALM load credit) of of the Parties and each of the parties to the RAA entitled to share in the charges, for the most recent month.

2. In the event all of the Parties and all of the parties to the RAA have incurred charges with respect to an Emergency, the charges related to that Emergency shall be distributed as approved by the PJM Board.

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SCHEDULE 13

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection. The Office of Interconnection is obligated under the Amended Operating Agreement and this Agreement to meet these responsibilities:

1. **New Parties.** With regard to the addition, withdrawal or removal of a Party:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM West Region, including entities whose participation in the Agreement will expand the boundaries of the PJM West Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

(b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. **Implementation of West Reliability Assurance Agreement.** With regard to the implementation of the provisions of this Agreement:

(a) Establish and operate the PJM Capacity Credit Market as described in Schedule 11 of the Amended Operating Agreement;

(b) Receive all required data and forecasts from the Parties;

(c) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the obligations imposed under this Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

(d) Monitor the compliance of each Party with its obligations under this Agreement;

(e) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of this Agreement;

(f) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(g) Establish the capability and deliverability of Capacity Resources consistent with the requirements of this Agreement;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer this Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM West Region;

(k) Determine and declare that an Emergency exists or ceases to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Administer and implement for the PJM West Region the automatic reserve sharing processes required by ECAR and MAIN;

(n) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC MAIN or ECAR principles, guidelines, standards and requirements, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

SCHEDULE 14

ZONES WITHIN THE PJM WEST REGION AND MAAC CONTROL ZONE

ZONES IN PJM WEST REGION: ZONE 12-15

ZONES IN MAAC CONTROL ZONE: ZONES 1-11

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SCHEDULE 15

DATA SUBMITTALS

A. To perform the studies required to determine the Forecast Pool Requirement and Accounted-For Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Capacity Resources and load forecasts (including seasonal and average weekly peaks) shall be submitted.

5. On or before the date specified in the PJM Manuals, adjustments to forecasts shall be submitted.

6. On or before the date or schedule for updates specified in the PJM Manuals, revisions to capacity and load forecasts (including the plans for satisfying the Accounted-For Obligation of the Party) shall be submitted.

7. Capacity plans or revisions to previously submitted capacity plans, required under Schedule 6.

8. As desired by a Party, revisions to monthly peak load forecasts may be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

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SCHEDULE 16

PARTIES TO THE PJM WEST RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

Harrison REA Inc.

City of New Martinsville

City of Philippi

Letterkenny Industrial Development Authority-PA

Old Dominion Electric Cooperative

Town of Front Royal

Hagerstown

Borough of Chambersburg

Town of Williamsport

Thurmont

Allegheny Electric Coopertive, Inc.

Allegheny Power

AES New Energy, Inc.

BP Energy Co.

Commonwealth Edison Company

Commonwealth Edison Company of Indiana

Dayton Power & Light Company (The)

American Municipal Power-Ohio, Inc.

American Electric Power Service Corporation on behalf of its affiliates:

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Kingsport Power Company

Ohio Power Company

Wheeling Power Company

Allegheny Energy Supply Company, L.L.C.

Blue Ridge Power Agency, Inc.

Central Virginia Electric Cooperative

City of Dowogiac

Hoosier Energy REC, Inc.

Indiana Municipal Power Agency

Ormet Primary Aluminum Corporation

City of Sturgis

Wabash Valley Power Association, Inc.

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SCHEDULE 17

CAPACITY ADEQUACY STANDARDS AND PROCEDURES FOR THE COMMONWEALTH EDISON ZONE DURING THE INTERIM PERIOD

A. This schedule sets forth the standards and procedures to assure capacity adequacy in the zone (ComEd Zone) of Commonwealth Edison Company (including Commonwealth Edison Company of Indiana) (ComEd) during the Interim Period. For purposes of this schedule, the Interim Period is the time period beginning upon the date that the ComEd Zone is added to the PJM West Region and concluding upon May 31, 2005; provided, however, that if the American Electric Power Zone is not expected to be added to the PJM West Region by such date, the parties shall meet before such date to address the capacity adequacy requirements for the ComEd Zone to be in effect after such date. Except as may be waived during the Phase-in Period as set forth in section L of this Schedule 17, all Load-serving Entities serving load in the ComEd Zone during the Interim Period shall comply with the provisions of this schedule, and with all other provisions of this Agreement and its attached schedules to the extent not inconsistent with the provisions of this Schedule 17.

B. Interim Installed Capacity Requirement. The Interim Installed Capacity Requirement shall be determined as set forth in this section to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. The Interim Installed Capacity Requirement (IICR) shall be determined for each Interval as:

$$IICR = FZAP * (1 + IRM)$$

Where:

FZAP= the forecast accounting peak for the ComEd Zone for such Interval, which shall be the weather-normalized, 50/50 probability load prior to interruptible load being curtailed

IRM= the installed reserve margin applicable to such Interval, for which purpose, the PJM Board shall determine an installed capacity reserve margin for the summer-season Interval, and a separate installed capacity reserve margin for the non-summer-season Intervals

C. The Interim Installed Capacity Requirement shall be projected for each Interval, no later than 60 days prior to the first day of such Interval, by PJM based on the IRM and the FZAP projected by the Electric Distributor for the ComEd Zone under the direction and supervision of, and subject to the final approval of, the Office of the Interconnection.

D. Parties can receive an adjustment to their load used in determining their Interim Capacity Obligation for Mandatory Interruptible Load that is operated under the mandatory direction of the Office of the Interconnection. The Office of the Interconnection shall establish and set forth in the PJM Manuals standards and procedures for the determination of Mandatory Interruptible Load, such standards and procedures to be consistent with MAIN Guide 3B, MAIN Guide 6, and MAIN audit standards.

E. Each Partys Interim Capacity Obligation for each billing month during an Interval shall be determined as:

Party Interim Capacity Obligation = {IICR * (FPAP/FZAP)} - {FPMIL * (1 + IRM)}

Where:

FPAP = the forecasted weather-adjusted coincident annual peak of the end-users in the ComEd Zone for which the Party is responsible for that month (in accordance with Section I of this Schedule), as determined by the Electric Distributor for the ComEd Zone under the direction and supervision of, and subject to the approval of, the Office of the Interconnection, in accordance with the procedures set forth in the PJM Manuals.

FPMIL = the forecast Mandatory Interruptible Load adjustments to the Party for the Zone for the billing month determined pursuant to this schedule.

For purposes of this paragraph, FZAP shall be determined for the annual peak of the ComEd Zone.

Any disputes concerning the determination of the Party Interim Capacity Obligation shall be resolved pursuant to the dispute resolution provisions of the Amended Operating Agreement.

F. Each Party shall satisfy its Interim Capacity Obligation by committing the installed capacity, rated at summer conditions, of Capacity Resources (Installed Capacity). A Party may use capacity credits to meet all or part of its capacity obligations under this Schedule. For this purpose, the Office of the Interconnection shall administer monthly and Interval capacity credit markets for the ComEd Zone in accordance with Schedule 11 to the Amended Operating Agreement, provided that the credits sold and purchased shall be on an Installed Capacity basis, shall only be used to meet capacity obligations in the ComEd Zone, and shall not include daily markets.

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IssuedOn: April 19, 2004
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER04-521-000, issued March 18, 2004, 106 FERC 61,253.

G. For purposes of this Schedule, the capability of qualifying Capacity Resources shall be determined in accordance with Schedule 9 and the deliverability of such resources shall be determined in accordance with Schedule 10 (provided that the test for deliverability shall be as to the ComEd Zone, rather than as to the PJM Region).

IssuedBy:	Craig Glazer	Effective:	May 1, 2004
	Vice President, Governmental Policy		
IssuedOn:	April 19, 2004		

H. Planned maintenance outage schedules for Installed Capacity committed to satisfy a Partys Interim Capacity Obligation may be modified only with the prior approval of the Office of the Interconnection.

I. Following the Phase-in Period, a Partys Interim Capacity Obligation shall be adjusted as of the first day of a calendar month to reflect a transfer of load from or to such Party where such transfer is to or from any other Party occurring on or at any time before the twentieth day of the immediately preceding month.

J. If a Partys Installed Capacity during any Interval is less than its Interim Capacity Obligation for such Interval, the Party shall be deficient and shall pay the deficiency charge set forth in section K of this Schedule. In addition, (i) a charge calculated in the same manner as that specified in Schedule 11, Section E (excluding, however, the forced outage adjustment factor), shall apply to a Party that specifies Mandatory Interruptible Load but that fails to deliver the full amount of such Mandatory Interruptible Load upon the request of the Office of the Interconnection; and (ii) a charge calculated in the same manner as that specified in Schedule 12 (excluding, however, the forced outage adjustment factor), shall apply to a Party that refuses to comply with, or otherwise fails to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement emergency procedures. Revenues from the charges specified in subsections (i) and (ii) of this Section J shall be distributed in a manner comparable to that set forth in Schedules 11 and 12, respectively.

K. The charge for deficiencies during any Interval required by Section J of this Schedule shall be equal to the product of: (i) the daily deficiency rate of $160 per megawatt-day, multiplied by (ii) the deficiency calculated under Section J of this Schedule (taking into account any change in such Partys Interim Capacity Obligation during such Interval in accordance with Section I of this Schedule), multiplied by (iii) the number of days in such Interval. The deficiency charge shall be paid only once by any Party during any Interval and shall be based on the greatest number of megawatts such Party is deficient on any day during such Interval. Deficiency charge revenues collected for an Interval under this Section K shall be distributed to Parties that meet their Interim Capacity Obligations for the ComEd Zone for such Interval (or as determined by the PJM Board in the event all such Parties have incurred deficiency charges for such Interval) in the same manner as set forth in Section B of Schedule 11 of this Agreement, provided, however, the Alternative Value calculation set forth in that Section shall not be applicable, and distribution shall be made only to Parties that meet their obligations under this Schedule.

L. Procedures during the Phase-in Period. For purposes of facilitating the implementation of the capacity adequacy procedures of this Schedule in the ComEd Zone, there shall be a Phase-in Period that shall commence on the first day of the Interim Period and conclude upon May 31, 2004. During the Phase-in Period, the following requirements and procedures shall apply.

The capacity obligations of this Schedule shall be waived as to any Load-Serving Entity (Non-Party LSE) serving load in the ComEd Zone for which ComEd has assumed all obligations of this Schedule for such Phase-in Period under this Section L.

ComEd shall be a Party to this Agreement during the Phase-In Period, and shall commit for the duration of the Phase-in Period Capacity Resources sufficient to satisfy: (i) the Interim Installed Capacity Requirement, less (ii) the sum of the Party Interim Capacity Obligations of any Load-Serving Entity that becomes a Party to this Agreement and fulfills the obligations of this Schedule for the duration of the Phase-in Period.

The IRM shall be 15 percent, applied to the forecast accounting peak of the ComEd Zone during the Phase-In Period. Installed Capacity shall not include any capacity forecast to be out of service during the Phase-in Period. For this purpose, the Office of the Interconnection shall audit and establish each Partys Installed Capacity no later than 45 days before the first day of the Phase-in Period. Each Party with capacity obligations during the Phase-in Period must disclose all known capacity outages for any part of the Phase-in Period during such audit. Installed Capacity committed pursuant to the audit must remain committed during the Phase-in Period as set forth in such audit.

The penalties and charges set forth in sections J and K shall apply during the Phase-in Period, but no capacity credit market shall be conducted for the Phase-in Period or any month thereof. Transfers of load among Parties shall not modify the transferor Partys or transferee Partys capacity obligations during the Phase-in Period.

Any Load-Serving Entity, as to all or part of the load it serves in the ComEd Zone, may elect to be a Party to this Agreement and subject to its rights and obligations, including the obligations of this Schedule, during the Phase-in Period. An LSE desiring to make this election must do so for the entire Phase-in Period and shall notify the Office of the Interconnection of such election by no later than 45 days prior to the first day of the Phase-in Period.

The allocation of financial transmission rights shall be modified for the ComEd Zone during the Phase-in Period in the manner set forth in Section 9 of Schedule 1 to the Amended Operating Agreement.

IssuedBy:	Craig Glazer	Effective:	May 1, 2004
	Vice President, Governmental Policy		
IssuedOn:	December 31, 2003		

Exhibit10(c)(3)

MASTER SETOFF AND NETTING

AGREEMENT

This Master Setoff and Netting Agreement (the Agreement) is made and entered into effective as of September 30, 2004, by and among PJM Interconnection, L.L.C. (PJM) and Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company, by and through American Electric Power Service Corporation, their agent (collectively, AEP).

RECITALS

Whereas, PJM and AEP have entered into the Amended and Restated Operating Agreement of PJM Interconnection, LLC, service agreements under the PJM Open Access Transmission Tariff, the Transmission Owners Agreement and the Reliability Assurance Agreement among Load Serving Entities in the PJM Control Area providing for the purchase, transmission, sale, exchange, or similar transactions with respect to electricity or other energy related services, including ancillary services, and such other additional contracts providing for payments among the Parties for various and sundry reasons as listed on Attachment A (collectively, the Documents).

Whereas, PJM and AEP acknowledge that based on this Agreement PJM will deal with AEP as if AEP Parties (as defined below) were a single legal entity, and not separate entities, for credit purposes. The Parties (as defined below) acknowledge that the AEP Parties, with the exception of Kingsport Power Company and Wheeling Power Company [1], are signatories to (1) an Interconnection Agreement, dated July 15, 1951, as modified and supplemented; (2) a System Integration Agreement, dated May 15, 2000, as supplemented, and (3) a Transmission Agreement, dated April 1, 1984, as modified and supplemented, (collectively, the AEP Documents) which provide for a net pooling arrangement and allocation of payments and liabilities for generation, load, transmission and third party transactions among the AEP Parties.

Whereas, PJM and AEP acknowledge they will benefit directly or indirectly from the this Agreement and that the promises made herein and other consideration exchanged between the Parties hereto in connection herewith constitute good and valuable consideration exchanged between the respective Parties, the receipt and sufficiency of which are hereby acknowledged.

NOW THEREFORE, for and in consideration of the mutual agreements herein made and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. Definitions. Capitalized terms used or incorporated by reference in this Agreement and not otherwise defined herein have the same meanings in this Agreement as given to them within the Documents. In the event of any conflict or inconsistency between a term defined herein and in any of the Documents, such term as used in the Documents shall in all events be controlling. All references within this Agreement are to this Agreement unless otherwise expressly stated. The following terms used in this Agreement are defined as follows:

AEP means the AEP Parties and AEPSC.

AEP Parties (collectively) or an AEP Party (individually) means the Eastern electric utility subsidiaries of American Electric Power Company, Inc., consisting of Appalachian Power Company,

[1] Kingsport Power Company and Wheeling Power Company have separate power supply agreements with Appalachian Power Company and Ohio Power Company, respectively, that govern power transactions between them.

Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company.

AEPSC means American Electric Power Service Corporation, as agent for the AEP Parties.

Collateral means security pledged or transferred in accordance with any of the Documents by AEP to secure payment or performance of any of its/their Obligations to PJM, including without limitation, letters of credit, cash and/or any guaranties.

Obligation or Obligations means each and every requirement or liability for which AEP is bound to PJM under the Documents, any Transaction thereunder, or this Agreement, whether financial or otherwise, including, without limitation, payment and delivery obligations, any debt, any obligation arising under a guaranty, any requirement to deliver or maintain Collateral, and each and every other obligation or requirement.

Party means PJM or AEP as the context indicates, and Parties means all of the foregoing.

Transaction or Transactions means each and every trade, transaction, or other open contractual commitment, between PJM and any AEP Party arising under any of the Documents.

2. Payment Netting. PJM will provide to AEP one or more invoices which shall be combined to comprise a single net bill for all activities, Transactions and/or Obligations incurred by the AEP Parties under the Documents during each billing period.

3. Netting Prior to Allocation of Liability. Each of the AEP Parties agrees that PJM shall determine a net amount for all activities Transactions and/or Obligations under the Documents prior to any allocation of liability by AEP among the AEP Parties in accordance with the AEP Documents for the activities and Obligations incurred by any and/or all AEP Parties, and each AEP Party agrees to save PJM harmless from actions that any one or more AEP Parties may take with respect to PJM pursuant to this Agreement.

4. Default and Remedies. A default by any one AEP Party of any of the Obligations under the Documents will constitute a default by all of the AEP Parties. PJM may exercise all rights to setoff of any amounts owed to the AEP Parties against any amount due and owing from AEP, including, but not limited, to any Collateral held by PJM. Notwithstanding the foregoing, it shall not be a default under PJMs credit policy, that Kingsport Power Company (Kingsport) and Wheeling Power Company (Wheeling) are not rated as investment grade by the corporate rating agencies relied on by PJM from time to time.

5. Mutual Representations and Warranties. Each Party represents and warrants to the other that (a) it is duly authorized to execute and deliver this Agreement and to perform its obligations hereunder and has taken all necessary actions to authorize such execution, delivery, and performance, (b) the person signing this Agreement on behalf of each Party is duly authorized to do so on its behalf, (c) this Agreement constitutes its legal, valid, and binding obligation, enforceable against it in accordance with its terms, subject to applicable bankruptcy, reorganization, insolvency, conservatorship, receivership, moratorium, or other similar laws affecting creditors rights generally and subject, as to enforceability, to equitable principles of general application (regardless of whether enforcement is sought in a proceeding in equity or at law), and (d) the location of its incorporation or organization and the location of its chief executive office are the locations set forth under its signature line to this Agreement.

6. AEP Representations. With respect to Kingsport and Wheeling specifically, AEP represents that: (a) neither Kingsport or Wheeling are currently, nor are they expected to be rated as investment grade; (b) neither Kingsport or Wheeling own any generation assets, and all transmission assets owned by such companies will be turned over operationally to PJM; (c) any and all entitlements to Kingsport and/or Wheeling from the operation of such transmission assets shall remain unencumbered and shall be included with all other funds due and owing to the AEP Parties, hereunder; (d) any and all retail load of Kingsport and Wheeling will be supplied by the AEP Parties, under exclusive supply contracts, and neither Kingsport or Wheeling will be Market Participants in any PJM market.

7. Interpretation and Headings. The Parties intend that this Agreement constitutes and should be deemed to be a master setoff agreement and that the Parties are and should be deemed to be master setoff agreement participants within the meaning of and as such terms are used in any law, rule, regulation, statute, or order applicable to the Parties rights herein, whether now or hereafter enacted or made applicable. The use of headings and subheadings in this Agreement, and the division of this Agreement into sections and sub-sections, are for convenience of reference only and shall not affect the interpretation or construction of this Agreement.

8. Governing Law. This Agreement shall be governed by, and construed in accordance with the laws of the State of Pennsylvania .

9. Assignment and Amendment. (a) This Agreement, and any rights to amounts payable to a Party there under, shall not be assigned by PJM or any AEP Party without the prior written consent of AEP or PJM, respectively, which consent shall not be unreasonably withheld. It shall be considered reasonable for a Party to withhold consent if the other Party is attempting to assign to an unaffiliated party.

(b) This Agreement may not be amended except by an amendment to this Agreement signed by each Party. Confirmations of Transactions under any of the Documents shall not serve as an amendment.

10. Conflicts and Inconsistencies; Confidentiality. In the event of any conflict or inconsistency between any provision of this Agreement and any provision of any of the Documents, the provision of the Documents shall govern and supercede the provisions of this Agreement. The contents of this Agreement shall be subject to the same confidentiality as provided for in the Amended and Restated Operating Agreement of PJM Interconnection, LLC.

11. Severability. In the event any one or more of the provisions contained in this Agreement should be held invalid, illegal, or unenforceable in any respect under the law of any jurisdiction, the validity, legality, and enforceability of the remaining provisions of this Agreement shall not in any way be affected or impaired thereby. If any portion of this Agreement is deemed or held to be invalid, illegal, or unenforceable, the Parties will use their best efforts to reform such portion of this Agreement to give effect to the original intention of the Parties as indicated herein.

12. Corrective or Supplemental Documents. The Parties agree that they will promptly execute any additional or corrective documentation and/or agreements reasonably necessary to correct or effectuate the intent of the Parties, as evidenced or recited herein.

13. No Waiver. A failure or delay in exercising any right, power, or privilege in respect of the Documents or this Agreement will not be presumed to operate as a waiver of that right, power, or privilege, and a single or partial exercise of any right, power, or privilege will not be presumed to preclude any subsequent or further exercise of that right, power, or privilege, or the exercise of any other right, power, or privilege.

14. Term. This Agreement shall continue in effect from the date hereof until terminated by either Party upon one hundred eighty (180) days prior written notice.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed, and to be effective as of the latest to occur of the following: (1) the date written above; (2) the date PJM received a fully executed original; and (3) the date on which Kingsport Power Company and Wheeling Power Company join PJM as evidenced by their due execution, delivery and effective date of the STANDARD FORM OF AGREEMENT TO BECOME A MEMBER OF THE PJM INTERCONNECTION, LLC.

[Signatures on following pages.]

PJM INTERCONNECTION, LLC

BY: /s/PHILIP HARRIS
PRINTED NAME: **Philip Harris**
TITLE: **President and Chief Executive Officer**

Location of state of incorporation or organization: Delaware
Location of chief executive office:

955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, PA 19403-2497

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

AS AGENT FOR THE AEP OPERATING COMPANIES

BY: /s/J. CRAIG BAKER
PRINTED NAME: **J. Craig Baker**
TITLE: **Senior Vice President Regulatory Services**

Location of state of incorporation or organization: New York
Location of chief executive office: 1 Riverside Plaza, Columbus, OH 43215

APPALACHIAN POWER COMPANY,

by its agent American Electric Power Service Corporation
BY: /s/SUSAN TOMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

Virginia
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

COLUMBUS SOUTHERN POWER COMPANY, by its agent American Electric Power Service Corporation
BY: /s/SUSAN TOMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

Ohio
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

INDIANA MICHIGAN POWER COMPANY,

by its agent American Electric Power Service Corporation
BY: /s/SUSAN TOMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

Indiana
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

KENTUCKY POWER COMPANY,

by its agent American Electric Power Service Corporation
BY: /s/SUSAN TOMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

Kentucky
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

[Signatures continued on following pages.]

OHIO POWER COMPANY,

by its agent American Electric Power Service Corporation
BY: /s/S USAN T OMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

Ohio
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

KINGSPORT POWER COMPANY,

by its agent American Electric Power Service Corporation
BY: /s/S USAN T OMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

Virginia
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

WHEELING POWER COMPANY,

by its agent American Electric Power Service Corporation
BY: /s/S USAN T OMASKY
PRINTED NAME: **Susan Tomasky**
TITLE: **Vice President**
Location of state of incorporation or organization:

West Virginia
Location of chief executive office:

1 Riverside Plaza, Columbus, OH 43215

ATTACHMENT A

ADDITIONAL CONTRACTS SUBJECT TO SETOFF AND NETTING

EXHIBIT 12

KENTUCKY POWER COMPANY

Computation of Consolidated Ratios of Earnings to Fixed Charges

(in thousands except ratio data)

	Year Ended December 31,				
	2000	**2001**	**2002**	**2003**	**2004**
FIXED CHARGES					
Interest on First Mortgage Bonds	$ 9,503	$ 6,178	$ 2,206	$ -	$ -
Interest on Other Long-term Debt	16,367	18,300	23,429	26,467	27,051
Interest on Short-term Debt	3,295	2,329	1,751	1,104	697
Miscellaneous Interest Charges	2,523	1,059	1,084	1,772	1,956
Estimated Interest Element in Lease Rentals	1,700	1,200	1,000	600	700
Total Fixed Charges	$ 33,388	$ 29,066	$ 29,470	$ 29,943	$ 30,404
EARNINGS					
Income Before Cumulative Effect of Accounting Change	$ 20,763	$ 21,565	$ 20,567	$ 33,464	$ 25,905
Plus Federal Income Taxes	17,884	9,553	9,235	9,764	8,974
Plus State Income Taxes (Credits)	2,457	489	1,627	(89)	(303)
Plus Fixed Charges (as above)	33,388	29,066	29,470	29,943	30,404
Total Earnings	$ 74,492	$ 60,673	$ 60,899	$ 73,082	$ 64,980
Ratio of Earnings to Fixed Charges	2.23	2.08	2.06	2.44	2.13

2004 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and

Managements Financial Discussion and Analysis

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority-owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEPR.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEPs electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	The Clean Air Act.
CenterPoint	CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco LP, all of which are not affiliated with AEP.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
DETM	Duke Energy Trading and Marketing L.L.C., a nonaffiliated risk management counterparty.
DOE	United States Department of Energy.
EITF	The Financial Accounting Standards Boards Emerging Issues Task Force.
EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held For Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
ERCOT	The Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, Consolidation of Variable Interest Entities.
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPP	Independent Power Producers.
ISO	Independent System Operator.
JMG	JMG Funding LP, a variable interest entity consolidated by OPCo.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.

KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas Co., a former AEP subsidiary.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP Systems Nonutility Money Pool.
NSR	New source review.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
Parent	American Electric Power Company, Inc.
PJM	PJM Interconnection, LLC; a regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
PURPA	The Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges, and nonderivative contracts held for trading purposes.
RTO	Regional Transmission Organization.
S&P	Standard & Poors.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes .
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities .
SFAS 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations .
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by TCC.
STPNOC	STP Nuclear Operating Company, a nonprofit Texas corporation which operates STP on behalf of its joint owners including TCC.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing to be made under the Texas Restructuring Legislation to review and finalize the amount of stranded costs,ifapplicable, and other true-up items and the recovery of such amounts.
TVA	Tennessee Valley Authority.
Utility Money Pool	AEP Systems Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of and transportation for fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- The ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain its operation and maintenance costs.
- Our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including membership and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AEP COMMON STOCK AND DIVIDEND INFORMATION

The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2004	$ 35.53	$ 31.25	$ 34.34	$ 0.35
September 30, 2004	33.21	30.27	31.96	0.35
June 30, 2004	33.58	28.50	32.00	0.35
March 31, 2004	35.10	30.29	32.92	0.35
December 31, 2003	30.59	26.69	30.51	0.35
September 30, 2003	30.00	26.58	30.00	0.35
June 30, 2003	31.51	22.56	29.83	0.35
March 31, 2003	30.63	19.01	22.85	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2004, AEP had approximately 130,000 registered shareholders.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SELECTED CONSOLIDATED FINANCIAL DATA

	2004	2003	2002	2001	2000
OPERATIONS STATEMENTS DATA			(in millions)		
Total Revenues	$ 14,057	$ 14,667	$ 13,427	$ 12,840	$ 10,854
Operating Income	1,991	1,754	1,923	2,310	1,869
Income Before Discontinued Operations, Extraordinary Items andCumulative Effect ofAccounting Changes	$ 1,127	$ 522	$ 485	$ 960	$ 177
Discontinued Operations Income (Loss), Net of Tax	83	(605)	(654)	41	134
Extraordinary Losses, Net of Tax	(121)	-	-	(48)	(44)
Cumulative Effect of Accounting Changes Gain(Loss), Net of Tax	-	193	(350)	18	-
Net Income (Loss)	$ 1,089	$ 110	$ (519)	$ 971	$ 267
BALANCE SHEET DATA			(in millions)		
Property, Plant and Equipment	$ 37,286	$ 36,021	$ 34,127	$ 32,993	$ 31,472
Accumulated Depreciation and Amortization	14,485	14,004	13,539	12,655	12,398
Net Property, Plant and Equipment	$ 22,801	$ 22,017	$ 20,588	$ 20,338	$ 19,074
Total Assets	$ 34,663	$ 36,781	$ 35,945	$ 40,432	$ 47,703
Common Shareholders Equity	$ 8,515	$ 7,874	$ 7,064	$ 8,229	$ 8,054
Cumulative Preferred Stocks of Subsidiaries (a) (d)	$ 127	$ 137	$ 145	$ 156	$ 161
Trust Preferred Securities (b)	$ -	$ -	$ 321	$ 321	$ 334
Long-term Debt (a) (b)	$ 12,287	$ 14,101	$ 10,190	$ 9,409	$ 8,980
Obligations Under Capital Leases (a)	$ 243	$ 182	$ 228	$ 451	$ 614
COMMON STOCK DATA					
Earnings (Loss) per Common Share:					
Income Before Discontinued Operations,Extraordinary Losses and Cumulative Effect ofAccounting Changes	$ 2.85	$ 1.35	$ 1.46	$ 2.98	$ 0.55
Discontinued Operations, Net of Tax	0.21	(1.57)	(1.97)	0.13	0.42
Extraordinary Losses, Net of Tax	(0.31)	-	-	(0.16)	(0.14)
Cumulative Effect of Accounting Changes, Net of Tax	-	0.51	(1.06)	0.06	-
Earnings (Loss) Per Share	$ 2.75	$ 0.29	$ (1.57)	$ 3.01	$ 0.83
Average Number of Shares Outstanding (in millions)	396	385	332	322	322
Market Price Range:					
High	$ 35.53	$ 31.51	$ 48.80	$ 51.20	$ 48.94
Low	$ 28.50	$ 19.01	$ 15.10	$ 39.25	$ 25.94
Year-end Market Price	$ 34.34	$ 30.51	$ 27.33	$ 43.53	$ 46.50
Cash Dividends Paid perCommon Share	$ 1.40	$ 1.65	$ 2.40	$ 2.40	$ 2.40
Dividend Payout Ratio (c)	50.9 %	569.0 %	(152.9)%	79.7 %	289.2 %
Book Value per Share	$ 21.51	$ 19.93	$ 20.85	$ 25.54	$ 25.01

(a) Including portion due within one year.

(b) See Trust Preferred Securities section of Note 17.
(c) Based on AEP historical dividend rate.
(d) Includes Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption which are classified in 2003 as Noncurrent Liabilities and in 2004 as Current Liabilities as the shares were redeemed in January 2005.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the U.S. Our electric utility operating companies provide generation, transmission and distribution service to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We have an extensive portfolio of assets including:

- 36,000 megawatts of generating capacity as of December 31, 2004, the largest complement of generation in the U.S., the majority of which has a significant cost advantage in many of our market areas. In 2004, we sold utility generating capacity of 3,800 megawatts located in Texas and approximately 280 megawatts of independent power generation located in Colorado and Florida.
- Approximately 39,000 miles of transmission lines, including the backbone of the electric interconnected grid in the Eastern U.S.
- 177,000 miles of distribution lines that deliver electricity to customers.
- Substantial coal transportation assets (7,065 railcars, 2,230 barges, 53 towboats and one active coal handling terminal with 20 million tons of annual capacity).
- 4,400 miles of gas pipelines in Texas with 118 billion cubic feet of gas storage facilities, which we sold on January 26, 2005.

BUSINESS STRATEGY

Our strategy is to focus on domestic electric utility operations. Our objectiveis to be an economical, reliable and safe provider of electric energy to the markets that we serve. We will achieve economic advantage by designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We will maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We will operate our competitive generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary our business strategy calls for us to:

Operations

- Invest in technology that improves the environment of the communities in which we operate.

- Maximize the value of our transmission assets through membership in PJM, ERCOT, and SPP.
- Continue maintaining and improving the quality of distribution service.
- Optimize generation assets by increasing availability and consequently increasing sales.

Regulation

- Focus on the regulatory process to fully recover our costs and earn a fair return while providing fair and reasonable rates to our customers while fulfilling our commitment to invest in environmental projects at our generating plants.

- Complete the sale of our generation assets in Texas and recover the associated stranded costs in compliance with the law.

Financial

Operate only those unregulated investments that are consistent with our energy expertise and risk tolerance and that provide reasonable prospects for a fair return and moderate growth.

Continue to improve credit quality and maintain acceptable levels of liquidity.
Achieve moderate but steady growth.

EXECUTIVE OVERVIEW

Utility Operations

Our Utility Operations, the core of our business, had a year of continued improvement despite some unfavorable operating conditions. Our results for the year reflect the increased demand from our industrial customers and sales growth in the residential and commercial classes. These are solid indicators that the economic recovery is reaching all sectors. We also realized a positive earnings impact due to a favorable court decision in Texas, which allows us to recover carrying costs for stranded costs in Texas. However, these favorable results were not sufficient to offset the absence of the wholesale capacity auction true-up revenues in 2004 and higher planned plant maintenance and distribution system reliability improvement work. Additionally, unfavorable weather due to a mild summer in 2004 lowered our revenues below expected norms and a significant late-December ice storm in parts of our eastern territory increased our storm damage repair operations and maintenance expenses.

In May 2004, we announced the reorganization of our distribution and customer service operations into seven regional utility divisions, placing operational authority into the hands of division presidents and their support staffs. With this new structure, we have created stronger utilities by moving the decision-making closer to the customer and other external stakeholders.

On October 1, 2004, we integrated our east region transmission and generation operations, commercial processes and data systems into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in this new environment. We are confident in our ability to participate successfully in the PJM market.

During 2004, we further stabilized our financial strength by:

Completing significant asset divestitures resulting in proceeds of approximately $1.4 billion.

Using the cash flows from our asset divestitures to reduce outstanding debt, resulting in an improved debt to capital ratio of 59.1% at December 31, 2004.
Stabilizing our credit ratings as indicated by Moodys change in outlook from stable to positive in August 2004.

While we were extremely successful during 2004 in reducing our outstanding debt and the related debt to total capital ratio from 64.6% to 59.1%, we have significant capital expenditures projected for the near-term. Through a combination of cash generated from operations and proceeds from our asset dispositions we expect to maintain the strength of our balance sheet and fund our capital expenditure program. After the completion of our remaining planned divestitures and after the results of our Texas true-up proceedings are finalized, we hope to recommend to the board gradual, sustainable increases to our current 35 cent per share quarterly common stock dividend.

Regulatory Matters

Ohio Rate Stabilization Plan

CSPCo and OPCo filed their rate stabilization plans on February 9, 2004 at the request of the Public Utility Commission of Ohio (PUCO) and the plans were approved, subject to rehearing,on January 26, 2005, with certain modifications. The plans are intended to provide rate stability, facilitate a competitive retail market, and provide for recovery of future environmental expenditures.

The approved plans include fixed annual percentage increases in the generation component of all customers' bills of 3% for CSPCo and 7% for OPCo in 2006, 2007 and 2008, along with the opportunity for additional generation-related increases upon PUCO review and approval. Additional generation-related increases averaging up to 4% per year for each company above the fixed annual percentage increases under the plans are possible. Distribution rates will remain fixed at the December 31, 2005 level through 2008 but could be adjusted for specified reasons with PUCO approval. Transmission rates will be adjusted based on FERC-approved OATT tariffs. We believe that these plans will favorably affect customers, shareholders and other stakeholders.

Texas Stranded Cost and Related Carrying Cost Recovery

The stranded cost recovery process in Texas continues to be very intense and time-consuming. The ultimate recovery of these assets is somewhat clearer given the recent CenterPoint decision; however, we anticipate a contentious stranded cost True-up Proceeding for TCC. The principal component of the process is the determination of TCCs net stranded generation costs regulatory asset. Other net true-up regulatory assets will also need to be recovered through customer transition charges. Although we believe that these assets are recoverable under the Texas restructuring legislation, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. TCC will seek to recover in its True-up Proceeding an amount in excess of the $1.6 billion recorded net true-up regulatory asset through December 31, 2004.

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying charges, through a nonbypassable competition transition charge in the regulated T&D rates, and through an additional transition charge for amounts that can be recovered through securitization. We cannot predict whether our full net stranded cost and other true-up regulatory assets will be approved for recovery.

TCC Rate Case

TCC has a base rate filing for its Texas wires business pending before the PUCT in which it is requesting an adjusted $41 million rate increase. A reduction in existing rates of between $48 million and $75 million is possible depending on the final treatment of affiliated transactions. Based on preliminary decisions of the PUCT, it appears that the best result we can expect is a $6 million rate increase. The PUCT order, when issued, will affect revenues prospectively.

PSO Rate Review

In February 2003, the Corporation Commission of the State of Oklahoma (OCC) filed an application requiring PSO to file all documents necessary for a general rate review. Intervenors and OCC Staff filed testimony recommending a decrease in annual existing rates of between $15 million and $36 million. PSOs current testimony supports a revenue deficiency of $28 million. As a consequence of this case, PSO also asserts that approximately $9 million of additional costs should be recovered through the fuel adjustment clause. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

Environmental Stewardship

In August 2004, a subcommittee of the Policy Committee of our Board of Directors prepared a report in response to a shareholder proposal entitled, An Assessment of AEPs Actions to Mitigate the Economic Impacts of Emissions Policies. This report summarizedassessed the actions that we are taking to mitigate the economic impact of increasing regulatory requirements, competitive pressures, and public expectations to significantly reduce carbon dioxide and other emissions. The comprehensive report made the following recommendations for managing the current challenge we face:

Design of control regimes - engage in persuasive, proactive advocacy of positive policy positions that ensure the rules governing such programs will operate in a transparent, fair and cost-effective manner.

Technology leadership - preserve our ability to utilize coal economically while meeting increasingly stringent emission control requirements.
Excellence in plant operations - consistently operate emission-controlled plants at high capacity factors.
Sophisticated decision-making tools - engage in complex decision-making processes to identify the mix of options that will minimize the cost to the consumer while at the same time factoring in the uncertainty inherent in the regulatory process.
Transparency - make actions transparent and understandable to shareholders, customers and stakeholders.
Partnerships - continue to seek out partners as we work out options to control greenhouse gas and other emissions.

The report concluded that the actions we have taken are a solid foundation for our future efforts to balance environmental policy and business opportunities. This conclusion is further evidenced by an award received in January 2005 from the Edison Electric Institute related to our advocacy efforts to support mercury cap-and-trade and the accompanying sulfur dioxide and nitrogen oxide regulations.

Asset Sales

While we made significant progress on our divestiture plans in 2004, we have four remaining assets to be sold. We sold the Pushan Power Plant, LIG Pipeline Company, Jefferson Island Storage & Hub, AEP Coal, four Independent Power Producers (IPPs), our U.K. operations, TCC and TNC generation assets, Numanco LLC and our 50% ownership in South Coast Power Limited during 2004, which generated proceeds of approximately $1.4 billion. In addition, on January 27, 2005, we announced the sale of 98% of our interest in Houston Pipeline Company, including gas and working capital, for $1 billion. This sale essentially completes our divestiture of natural gas assets in the U.S.

TCC Generation Assets

The largest remaining asset sale yet to close is the South Texas Project (STP) for approximately $333 million, followed by TCCs ownership interest in the Oklaunion asset for approximately $43 million. Under the existing PUCT rule, both of these assets must be sold before we can proceed with our Texas True-Up Proceeding. We have entered into agreements to sell TCCs interest in both facilities and we expect the sales to be completed in the first half of 2005, although the sale of Oklaunion could be delayed by litigation. TCC is considering seeking a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to closing of the sales of all generation assets.

Bajio

Our Bajio investment represents a 50% interest in a 600 MW natural gas-fired facility in Mexico. We have retained an advisor and the sale process is underway. Based on indicative bids received in the fourth quarter of 2004, we recorded an impairment of approximately $13 million. We expect a sale to close in 2006.

Pacific Hydro

Our Pacific Hydro investment represents a 20% interest in an Australian company that develops and operates renewable energy facilities including hydro, wind and geothermal facilities in the Pacific Rim. We have retained an advisor and have identified a preferred bidder. We expect the sale to close in the first half of 2005.

Fuel Costs

Market prices for coal, natural gas and oil have increased dramatically during 2004. These increasing fuel costs are the result of increasing worldwide demand, supply uncertainty, and transportation constraints, as well as other market factors. We manage price and performance risk, particularly for coal, through a portfolio of contracts of varying durations and other fuel procurement and management activities. We have fuel recovery mechanisms for about 50% of our fuel costs in our various jurisdictions. Additionally, about 20% of our fuel is used for off-system sales where power prices we receive for our power sales should recover our cost of fuel. Accordingly, approximately 70% of fuel cost increases are recovered. The remaining 30% of our fuel costs relate to Ohio and West

Virginia customers, where we do not have a fuel cost recovery mechanism. We currently have 100% and 85% of our projected coal needs for 2005 and 2006, respectively, under contract.

Capital Expenditures

Environmental

We previously announced plans to invest approximately $3.7 billion in capital from 2004 to 2010, and a total of $5 billion through 2020, to install pollution control equipment that preserves the low cost generation from our coal-fired power plants. Of the $3.7 billion environmental investment plan, $1.9 billion relates to compliance with current laws and the remaining $1.8 billion is intended to cover additional environmental controls that may be required in the future based on current legislative proposals to further reduce emissions and mercury. Forty-nine percent of our $3.7 billion capital plan relates to Ohio generation facilities, followed by Virginia and West Virginia for a combined 34 percent, and Kentucky with 12 percent. Our overall relationships with regulators are important to our growth strategy and our goal of producing low-cost electricity with minimal impact on the environment. We intend to support this investment program through the use of free cash flow and rate increases and therefore, at this time, do not anticipate material incremental leveraging. It is important that we manage the regulatory process to ensure that we receive fair recovery of our costs, including capital costs, as we fulfill our commitment to invest in environmental projects at our generating plants.

AdvancedTechnology

In conjunction withour environmental analysisissued in August 2004, we announced plans to construct synthetic-gas-fired power plant(s) withat least a combined1,000 MW of capacity in the next five to six years utilizing new integrated gasification combined cycle (IGCC) technology. We estimate that the new plant(s) will cost up to $1.7 billion, based on Electric Power Research Institute cost studies. Our detailed studies are underway to fully define the project.We have not determined a location for the plant, but it will likely be in one of our eastern states, because of ready access to coal and the need for capacity in the selected jurisdiction. We are currently performing site analysis and evaluation and at the same time working with state regulators and legislators to establish a framework for expedient recovery of this significant investment in new clean coal technology before final site selection. Our significant planned environmental investments and our commitment to IGCC technology reinforces our belief that coal will be a lower-emission domestic fuel source of the future and further signals our commitment to investing in clean, environmentally safe technology.

See further discussion of these matters in detail in the Notes to Financial Statements and later in Managements Discussion and Analysis under the heading of Significant Factors. We expect to diligently resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our investors.

OUTLOOK FOR 2005

We remain focused on the fundamental earning power of our utilities, and we are committed tomaintaining the strength ofour balance sheet. Our strategy for achieving these goals is well planned. We expect to:

- Continue to identify opportunities to increase the efficiency of our operations and capital expenditure program.
- Seek rate changes that are fair and reasonable and that allow us to make the necessary operational, reliability and environmental improvements to our system.
- Efficiently manage generating facilities to benefit our customers and to maximize off-system sales.
- Successfully operate unregulated investments such as our wind farms and our barge and river transport groups, which complement our core utility operations.
- Pursue new environmentally friendly, state of the art coal-fired power plants.

There are, nevertheless, certain risks and challenges including:

Rate activity such as the TCC wires rate case and the PSO rate case.

Completion of our asset sales, including the remaining TCC generation assets.
TCC stranded generation cost recovery, including the generation securitization, wholesale capacity auction true-up, fuel and clawback transition charge, and related carrying costs.
Fuel cost volatility and fuel cost recovery.
Financing and recovering the cost of capital expenditures, including environmental and new technology.

RESULTS OF OPERATIONS

Segments

In 2004, AEPs principal operating business segments and their major activities were:

Utility Operations:

- Domestic generation of electricity for sale to retail and wholesale customers
- Domestic electricity transmission and distribution

Investments - Gas Operations: (a)

- Gas pipeline and storage services

Investments - UK Operations: (b)

- Generation of electricity in the U.K. for sale to wholesale customers
- Coal procurement and transportation to our plants

Investments - Other: (c)

- Bulk commodity barging operations, wind farms, independent power producers and other energy supply-related businesses

(a) LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued operations during 2003 and were sold during 2004. 98% of the remaining HPL-related gas assets were sold during the first quarter of 2005.
(b) UK Operations were classified as discontinued during 2003 and substantially all operations were sold during 2004.
(c) Four independent power producers were sold during 2004.

Our consolidated Net Income (Loss) for the years ended December 31, 2004, 2003 and 2002 were as follows (Earnings and Average Shares Outstanding in millions):

	2004		2003		2002	
	Earnings	EPS	Earnings	EPS	Earnings	EPS
Utility Operations	$ 1,171	$ 2.96	$ 1,219	$ 3.17	$ 1,154	$ 3.47
Investments - Gas Operations	(51)	(0.13)	(290)	(0.76)	(99)	(0.29)
Investments - Other	78	0.20	(278)	(0.72)	(522)	(1.58)
All Other (a)	(71)	(0.18)	(129)	(0.34)	(48)	(0.14)

Income Before Discontinued Operations, Extraordinary Item and Cumulative	1,127	2.85	522	1.35	485	1.46
Effect of Accounting Changes						
Investments - Gas Operations	(12)	(0.03)	(91)	(0.24)	8	0.02
Investments - UK Operations	91	0.23	(508)	(1.32)	(472)	(1.42)
Investments - Other	4	0.01	(6)	(0.01)	(190)	(0.57)
Discontinued Operations, Net of Tax	83	0.21	(605)	(1.57)	(654)	(1.97)
Extraordinary Loss on Texas Stranded Cost Recovery- Utility Operations,	(121)	(0.31)	-	-	-	-
Net of Tax						
Utility Operations	-	-	236	0.61	-	-
Investments - Gas Operations	-	-	(22)	(0.05)	-	-
Investments - UK Operations	-	-	(21)	(0.05)	-	-
Investments - Other	-	-	-	-	(350)	(1.06)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	193	0.51	(350)	(1.06)
Net Income (Loss)	$ 1,089	$ 2.75	$ 110	$ 0.29	$ (519)	$ (1.57)
Weighted Average Shares Outstanding		396		385		332

(a) All Other includes the Parents interest income and expense, as well as other nonallocated costs.

2004 Compared to 2003

Income Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes in 2004 increased $605 million compared to 2003 due to increased retail margins and stranded generation carrying cost deferrals at TCC in our Utility Operations, improved margins and lower impairments in our Gas Operations and Investments - Other segments, gains realized on the sale of assets, and lower provisions for penalties and other expenses booked by the Parent. These increases were offset, in part, by decreased margins due to the divestiture of Texas generation assets, the loss of the capacity auction true-up revenues in Texas, and higher operations and maintenance expense, all occurring in our Utility Operations segment.

Our Net Income for 2004 of $1,089 million, or $2.75 per share, includes income, net of tax, on discontinued operations of $83 million, resulting primarily from a gain on the sale of our UK Operations, and an extraordinary loss of $121 million, net of tax, which represents a provision for probable disallowance to the stranded cost net regulatory assets of TCC based on PUCT orders in nonaffiliated true-up proceedings. Our Net Income for 2003 of $110 million, or $0.29 per share, includes a $605 million loss, net of tax, on discontinued operations and $193 million of income, net of tax, from the cumulative effect of changing our accounting for asset retirement obligations and for certain trading activities.

Average shares outstanding increased to 396 million in 2004 from 385 million in 2003 due to a common stock issuance in 2003 and common shares issued related to our incentive compensation plans. The additional average shares outstanding decreased our 2004 earnings per share by $0.08.

2003 Compared to 2002

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Changes in 2003 increased compared to 2002 due to increased wholesale earnings, lower impairment and other charges, and reduced operations and maintenance expenses. This increase was offset, in part, by milder summer weather and continuing weakness in the economy. Our Net Income for 2003 of $110 million, or $0.29 per share, includes a $605 million loss, net of tax, on discontinued operations and $193 million of income, net of tax, from the cumulative effect of FASB-required changes to our accounting for asset retirement obligations and for certain trading activities. Our Net Loss for 2002 of $519 million, or ($1.57) per share, includes a $654 million loss, net of tax, from discontinued operations and a $350 million, net of tax, charge for implementing a newly issued accounting pronouncement related to the impairment of goodwill.

Inthe fourth quarter of 2003 we concluded that the UK Operations and LIG were not part of our core business and we began actively marketing each of these investments. The UK Operations consisted of generation and trading operations that sell to wholesale customers. LIGs operations included 2,000 miles of intrastate gas pipelines in Louisiana and 9 Bcf of natural gas storage capacity. Poor market conditions also affected our merchant generation, other gas pipeline and storage assets, goodwill associated with these investments and various other assets. Based on market factors, as measured by a combination of indicative bids from unrelated interested buyers, independent appraisals, and estimates of cash flows, we recognized impairment losses of $960 million, net of tax.

Average shares outstanding increased to 385 million in 2003 from 332 million in 2002 due to a common stock issuance in March 2003. The additional average shares outstanding decreased our 2003 earnings per share by $0.04.

Our results of operations are discussed below according to our operating segments.

Utility Operations

	2004	2003	2002
		(in millions)	
Revenues	$ 10,633	$ 11,015	$ 10,491
Fuel and Purchased Power	3,615	3,746	3,132
Gross Margin	7,018	7,269	7,359
Depreciation and Amortization	1,256	1,250	1,276
Other Operating Expenses	3,772	3,554	3,811
Operating Income	1,990	2,465	2,272
Other Income (Expense), Net	353	27	170
Interest Charges and Preferred Stock Dividend Requirements	616	664	642
Income Tax Expense	556	609	646
Income Before Discontinued Operations, ExtraordinaryItem and Cumulative Effect of Accounting Charges	$ 1,171	$ 1,219	$ 1,154

Summary of Selected Sales Data

For Utility Operations

For the Years Ended December 31, 2004, 2003 and 2002

	2004	2003	2002
Energy Summary		(in millions of KWH)	
Retail:			
Residential	45,770	45,308	37,900
Commercial	37,204	36,798	30,380
Industrial	51,484	49,446	51,491
Miscellaneous	3,099	3,026	2,261
Subtotal	137,557	134,578	122,032
Texas Retail and Other	925	2,896	18,162
Total	138,482	137,474	140,194
Wholesale	82,870	72,977	70,661

Weather Summary	2004	2003 (in degree days)	2002
Eastern Region			
Actual - Heating	2,991	3,219	2,886
Normal - Heating (a)	3,086	3,075	3,071
Actual - Cooling	876	756	1,247
Normal - Cooling (a)	974	976	969
Western Region (b)			
Actual - Heating	1,382	1,554	1,566
Normal - Heating (a)	1,624	1,622	1,622
Actual - Cooling	2,005	2,144	2,233
Normal - Cooling (a)	2,149	2,138	2,128

(a) Normal Heating/Cooling represents the 30-year average of degree days.

(b) Western Region statistics represent PSO/SWEPCo customer base only.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004

Income from Utility Operations Before Discontinued Operations, Extraordinary Item and

Cumulative Effect of Accounting Changes

(in millions)

Year Ended December 31, 2003		$ 1,219
Changes in Gross Margin:		
Retail Margins	65	
Texas Supply Margins	(105)	
Wholesale Capacity Auction True-up Revenues	(215)	
Off-System Sales	10	
Other Revenue	(6)	
		(251)
Changes in Operating and Other Expenses:		
Operations and Maintenance	(205)	
Asset Impairments and Other Related Charges	10	
Depreciation and Amortization	(6)	
Taxes, Other	(23)	
Carrying Costs on Texas Stranded Costs	302	
Other Income (Expense), Net	24	
Interest Charges	48	
		150
Income Tax Expense		53
Year Ended December 31, 2004	$	1,171

Income from Utility Operations Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes decreased $48 million to $1,171 million in 2004. Key drivers of the decrease include a $251 million decrease in gross margin; offset in part by a $150 million decrease in operating and other expenses and a $53 million decrease in income tax expense.

The major components of the net decrease in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

- The increase in retail margins of our utility business over the prior yearwas due to increased demand in both the East and the West as a consequence of higher usage in most classes and customer growth in the residential and commercial classes. Commercial and industrial demand also increased, resulting from the economic recovery in our regions. Milder weather during the summer months of 2004 partially offset these favorable results.
- Our Texas Supply business experienced a $105 million decrease in gross margin principally due to the partial divestiture of a portion of TCCs generation assets to support Texas stranded cost recovery. This resulted in higher purchased power costs to fulfill contractual commitments.
- Beginning in 2004, the wholesale capacity auction true-up ceased per the Texas Restructuring Legislation. Related revenues are no longer recognized, resulting in $215 million of lower regulatory asset deferrals in 2004. For the years 2003 and 2002, we recognized the revenues for the wholesale capacity auction true-up for TCC as a regulatory asset for the difference between the actual market prices based upon the state-mandated auction of 15% of generation capacity and the earlier estimate of market price used in the PUCTs excess cost over market model.
- Margins from off-system sales for 2004 were $10 million higher than in 2003 due to favorable optimization activity, somewhat offset by lower volumes.

Utility Operating and Other Expenses changed between the years as follows:

- Operations and Maintenance expense increased $205 million due to a $110 million increase in generation expense primarily due to an increase in maintenance outage weeks in 2004 as compared to 2003 and increases in related removal and chemical costs, PJM expenses and operating expenses for the Dow Plaquemine Plant. Additionally, distribution maintenance expense increased $54 million from system improvement and reliability work and damage repair resulting primarily from major ice storms in our Ohio service territory during December 2004. Other increases of $81 million include ERCOT and transmission cost of service adjustments in 2004 and increased employee benefits, insurance, and other administrative and general expenses magnified by favorable adjustments in 2003. These increases were offset, in part, by $40 million due to the conclusion in 2003 of the amortization of our deferred Cook nuclear plant restart expenses.
- 2003 included a $10 million impairment at Blackhawk Coal Company, a nonoperating wholly-owned subsidiary of I&M, which holds western coal reserves.
- Depreciation and Amortization expense increased $6 million primarily due to a higher depreciable asset base, including the addition of capitalized software costs, increased amortization of regulatory assets, and the consolidation in July 2003 of JMG by OPCo (which had no impact on net income). These increases more than offset the decrease in expense at TCC, which is due primarily to the cessation of depreciation on plants classified as held for sale.
- Taxes Other Than Income Taxes increased $23 million due to increased property tax values and assessments, higher revenue taxes due to the increase in KWH sales, and favorable prior year franchise tax adjustments.
- Carrying Costs on Texas Stranded Costs of $302 millionrepresent TCCs debt component of the carrying costs accrued on its net stranded generation costs and its capacity auction true-up asset (see Texas Restructuring and Texas True-Up Proceedings under Customer Choice and Industry Restructuring).
- Interest Charges decreased $48 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates.
- Income Tax expense decreased $53 million due to the decrease in pretax income and tax return adjustments.

2003 Compared to 2002

Reconciliation of Year Ended December 31, 2002 to Year Ended December 31, 2003

Income from Utility Operations Before Discontinued Operations, Extraordinary Item and

Cumulative Effect of Accounting Changes

(in millions)

Year Ended December 31, 2002		$ 1,154
Changes in Gross Margin:		
Retail Margins	(145)	
Texas Supply	(85)	
Wholesale Capacity Auction Revenues	(44)	
Off-System Sales	162	
Other Wholesale Transactions	(70)	
Other Revenue	92	
		(90)
Changes in Operating and Other Expenses:		
Operations and Maintenance	183	
Asset Impairments and Other Related Charges	43	
Depreciation and Amortization	26	
Taxes, Other	31	
Other Income (Expense), Net	(143)	
Interest Charges	(22)	
		118
Income Tax Expense		37
Year Ended December 31, 2003		$ 1,219

Income from Utility Operations Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes increased $65 million to $1,219 million in 2003. Key drivers of the increase include a $118 million decrease in operating and other expenses and a $37 million decrease in income tax expense; offset in part by a $90 million decrease in gross margin.

The major components of our decrease in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

The decrease in retail margins from the prior year was due to lower retail demand from mild weather primarily in the East, and lower industrial demand in both the East and West service territories primarily due to the continued slow economic recovery in 2003.

Our Texas Supply business experienced a decrease in gross margin principally due to provisions for probable final Texas fuel and off-system sales disallowances of $102 million and the loss of margin contributions from two Texas Retail Electric Providers (REPs) sold to Centrica in December 2002. The demand from the two REPs was replaced, in part, with a power supply contract with Centrica that extended through 2004.

In 2003 and 2002, we recognized the revenues for the wholesale capacity auction true-up at TCC as a regulatory asset representing the difference between the actual market prices based upon state-mandated auctions of 15% of economically available generation capacity and the earlier estimate of market prices used in the PUCTs excess cost over market model. The amount recognized in 2003 was $218 million, or $44 million less than in 2002.

Margins from off-system sales for 2003 improved by $162 million over 2002 due to increased volumes, higher prices, and plant availability.

Other wholesale transactions represent the transition electric trading book, associated with our decision to exit from markets where we do not own assets. During the fourth quarter of 2002, we exited trading activities that were not related to the sale of power from owned-generation. This reduced comparative 2003 utility earnings by approximately $70 million.

Other revenue includes transmission revenues, third party revenues and miscellaneous service revenues. Transmission revenues were $45 million higher than the prior year primarily due to the effect of higher off-system sales volumes. Service revenues exceeded the prior year by $47 million primarily due to higher reconnect, temporary service fees, rental on pole attachments, transmission rentals, forfeited discounts, and other miscellaneous items.

Utility Operating and Other Expenses changed between the years as follows:

Maintenance and Other Operation expenses decreased $183 million due to our continued efforts to reduce costs where practical, primarily administrative and general expenses, labor and employee related expenses, of approximately $120 million. The sale of the Texas REPs reduced expenses supporting the back office by $75 million in 2003, and unfavorable severance costs in 2002 contributed to the period-to-period favorable variance by $65 million. These decreases were offset, in part, by approximately $24 million in damage repair as a result of severe storms in the Midwest, and higher pension and postretirement benefit costs of approximately $60 million in 2003.

Asset Impairments and Other Related Charges decreased $43 million from the prior year. 2002 included $38 million in impairments of certain moth-balled Texas gas plants, all related to TNC, a $12 million loss of investment value in some early-stage start up technologies, and a $3 million loss of investment value in water heater assets. Asset impairments in 2003 at Blackhawk Coal Company were $10 million.

Depreciation and Amortization expense decreased $26 million primarily due to the change in our accounting for asset retirement obligations. The change caused similar offsetting increases in Maintenance and Other Operation expense.

The decrease in Taxes, Other was primarily due to reduced gross receipts tax as a result of the sale of the Texas REPs and prior period franchise tax return true-ups.

Other Income (Expense), Net decreased $143 million primarily due to a net gain on sale of the Texas REPs in 2002.

Interest Charges increased $22 million from the prior period due to expensing debt reacquisition costs previously deferred under the regulatory accounting model and the consolidation in July 2003 of JMG by OPCo (which had no impact on net income), as well as the maturity of short-term debt.

Income Tax expense decreased $37 million primarily due to state tax return adjustments partially offset by higher pretax income.

Investments - Gas Operations

	2004	2003	2002
		(in millions)	
Revenues	$ 3,114	$ 3,126	$ 2,283
Purchased Gas	2,955	2,995	2,171
Gross Margin	159	131	112
Operating Expenses	144	484	227
Operating Income (Loss)	15	(353)	(115)
Other Income (Expense), Net	(33)	(8)	(4)
Interest Charges and Minority Interest in Finance Subsidiary	57	56	50
Income Tax Benefit	24	127	70
Net Loss Before Discontinued Operations and Cumulative Effect of Accounting Changes	$ (51)	$ (290)	$ (99)

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31,2004

Loss from Investments - Gas Operations Before Discontinued Operations and Cumulative Effect of Accounting Changes

(in millions)

Year Ended December 31, 2003		$(290)
Change in Gross Margin		28
Changes in Operating And Other Expenses:		
Operations and Maintenance	21	
Depreciation and Amortization	7	
Taxes, Other	(3)	
Other Income (Expense), Net	(25)	
Interest Charges	(1)	

	(1)
Asset Impairments and Other Related Charges	315
Income Tax Benefit	(103)
Year Ended December 31, 2004	$(51)

Our loss from Gas Operations before discontinued operations and cumulative effect of accounting changes decreased $239 million to $51 million in 2004. The key driver of the decrease was $315 million of impairments recorded in 2003, partially offset by a $103 million decrease in income tax benefit principally related to the impairments.

The major components of the net increase in gross margin of $28 million, defined as gas revenues net of related purchased gas are as follows:

2003 included losses of $31 million related to the servicing of a single contract.

Pipeline and pipeline optimization margins improved by $24 million.
Storage margins decreased by $53 million, largely due totiming on recognition of storage margins.
Prior year transitional gas trading activities yielded losses of $26 million.

Gas Operating and Other Expenses remained flat year-over-year. However, significant line-item changes are as follows:

Operations and Maintenance expenses decreased $21 million as a result of gas trading activities that have since been ceased.

Depreciation and Amortization expense decreased $7 million primarily due to the 2003 asset impairments.
Other Income (Expense), Net decreased $25 million primarily due to the write-off of stranded intercompany debt between a discontinued operation and its parent.

2003 Compared to 2002

Reconciliation of Year Ended December 31, 2002 to Year Ended December 31, 2003

Loss from Investments - Gas Operations Before Discontinued Operations and Cumulative Effect of Accounting Changes

(in millions)

Year Ended December 31, 2002		$ (99)
Change in Gross Margin		19
Change in Operating And Other Expenses:		
Operations and Maintenance	6 0	
Depreciation and Amortization	(5)	
Taxes, Other	3	
Other Income (Expense), Net	(4)	
Interest Charges	(6)	
		48
Asset Impairments and Other Related Charges		(315)
Income Tax Benefit		57

Year Ended December 31, 2003	$ (290)

The loss from our Gas Operations before discontinued operations and cumulative effect of accounting changes of $290 million increased $191 million from 2002. This increase is primarily due to impairments recorded to reflect the reduction in the value of our gas assets. In the fourth quarter of 2003, we recognized impairments and other related charges of $315 million associated with HPL assets and goodwill based on market indicators supported by indicative bids received for LIG. These bids led us to conclude that purchasers were no longer willing to pay higher multiples for historic cash flows which included trading activities. Our previous operating strategy included higher risk tolerances associated with trading activities in order to achieve such operating results.

Partially offsetting the 2003 impairments, Gas Operations earnings increased $124 million year-over-year as a result of the following:

Improvement in the transition gas segment margins of $62 million due to prior year losses in the options trading portfolio and lower operating expenses of $43 million.

Decline in trading optimization of $43 million due to lower risk tolerances and limits in 2003 as compared to 2002.
2003 included losses of $31 million related to the servicing of a single contract.
A $57 million increase in income tax benefit due to the increase in pretax losses.

Investments - UK Operations

2004 Compared to 2003

Income from our Investments - UK Operations segment (all classified as Discontinued Operations) increased to $91 million in income, which includes a gain on sale of $128 million in 2004, compared with a loss of $508 million in 2003, before the cumulative effect of accounting change. During late 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. In July 2004, we completed the sale of substantially all operations and assets within our Investments - UK Operations segment.

2003 Compared to 2002

The loss before cumulative effect of accounting change from our UK Operations of $508 million for 2003 increased by $36 million from 2002 due primarily to a $375 million, net of tax, impairment and other related charges recorded during the fourth quarter of 2003 compared with a net of tax impairment of $414 million recorded in 2002. During 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. As a result, we wrote down our UK investment based on bids received from interested, unrelated buyers. The 2003 loss also includes $157 million of pretax losses associated with commitments for below-market forward sales of power, which went beyond the date of the anticipated sale of these plants. We also experienced operating losses as a result of the deterioration of pretax trading margins of $83 million associated with U.K. power and $29 million associated with coal and freight.

Investments - Other

2004 Compared to 2003

Income before discontinued operations from our Investments - Other segment increased from a loss of $278million in 2003to income of $78 million in 2004.

The key components of the increase in income were as follows:

We recorded an after tax gain of approximately $64 million resulting from the sale in July 2004 of our ownership interests in our two independent power producers in Florida (Mulberry and Orange).

We recorded an after tax gain of approximately $31 million resulting from the sale of our 50% interest in South Coast Power Limited, owner of the Shoreham Power Station in the U.K.
Our results in 2004 did not include $257 million of after tax impairments recorded in 2003, related to our investment in the Colorado IPPs, AEP Coal and the Dow power generation facility.
Our AEP Texas Provider of Last Resort (POLR) entity recorded a $6 million after tax provision for uncollectible receivables in 2003.
AEP Resources decreased its loss by $33 million in 2004 versus 2003, primarily due to lower interest expense of $19 million resulting from equity capital infusions in mid and late 2003 that were used to reduce debt and other corporate borrowings and $6 million related to increased earnings from Bajio.
AEP Pro Serv reduced losses from $6 million to $1 million of income, primarily due to operations winding down in 2004.

Offsetting these increases was the absence during 2004 of a $31 million gain recorded in 2003 primarily related to the sale of Mutual Energy, AEPs Texas REP, and a $7 million decrease in net income as a result of having sold four of our IPPs in 2004.

Discontinued operations includes the Eastex Cogeneration facility, which was sold in 2003 and Pushan Power Plant, which was sold in March 2004.

2003 Compared to 2002

The loss before discontinued operations and cumulative effect of accounting changes from our Investments - Other segment decreased by $244 million to $278 million in 2003. The decrease was primarily due to asset impairment charges of $257 million, net of tax, recorded in 2003 compared to impairments of $392 million, net of tax, recorded in 2002. Impairments in 2003 included losses of $46 million, net of tax, for two of our independent generation facilities due to market conditions in 2003; $168 million, net of tax, for the Dow facility due to the current market conditions and litigation; and coal mining asset impairments of $44 million, net of tax, based on bids from unrelated parties. We also had lower international development costs and reduced interest expenses during 2003.

All Other

2004 Compared to 2003

The Parents 2004 loss decreased $58 million from 2003 due to a $40 million provision for penalties booked in 2003, compared to $20 million in 2004, a $12 million decrease in expenses primarily resulting from lower insurance premiums and lower general advertisement expenses in 2004 and a $20 million decrease in income taxes related to federal tax accrual adjustments. Interest income was $9 million lower in the current period due to lower cash balances, along with higher interest rates on invested funds in 2003. Additionally, parent guarantee fee income from subsidiaries was $4 million lower due to the reduction of trading activities. There is no effect on consolidated net income for this item.

2003 Compared to 2002

The Parents 2003 loss increased $81 million over 2002 primarily from higher interest costs due to increased long-term debt at the parent level and reduced reliance on short-term borrowings as well as a $40 million provision for penalties booked in 2003.

Income Taxes

The effective tax rates for 2004, 2003 and 2002 were 33.5%, 40.3% and 38.8%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, energy production credits, amortization of investment tax credits, and other state income tax and federal income tax adjustments. The decrease in the effective tax rate in 2004 versus the comparative period is primarily due to more favorable federal income tax adjustments in 2004 versus 2003 and changes in permanent differences. The effective tax rates remained relatively flat between 2002 and 2003.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2004, we improved our financial condition as a consequence of the following actions and events:

We reduced short-term debt by $303 million, terminated our Euro revolving credit facility, completed approximately $2.3 billion of long-term debt redemptions, including optional redemptions such as our Steelhead financing, and funded $770 million of debt maturities; and

We maintained stable credit ratings across the AEP System. Moodys Investor Services assigned a positive outlook on AEP Inc.s ratings, while the rated subsidiaries continued to have ratings with stable outlooks.

Capitalization ($ in millions)

	2004			2003		
Common Equity	$8,515	40.6	%	$ 7,874	35.1	%
Preferred Stock	61	0.3		61	0.3	
Preferred Stock (Subject to Mandatory Redemption)	66	0.3		76	0.3	
Long-term Debt, including amounts due within one year	12,287	58.7		14,101	62.8	
Short-term Debt	23	0.1		326	1.5	
Total Capitalization	$20,952	100.0	%	$ 22,438	100.0	%

Our $2.6 billion in cash flows from operations, combined with our reduction in cash expenditures for investments in discontinued operations, the proceeds from asset sales, a reduction in the dividend beginning in the second quarter of 2003 and the use of a portion of our cash on hand, allowed us to reduce long-term debt by $1.8 billion and short-term debt by $303 million.

Our common equity increased due to earnings exceeding the amount of dividends paid in 2004, a discretionary $200 million cash contribution to our pension fund, which allowed us to remove a portion of the charge to equity related to the underfunded plan,and the issuance of $17 million of new common equity (related to our incentive compensation plans).

As a consequence of the capital changes during 2004, we improved our ratio of debt to total capital from 64.6% to 59.1% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

In February 2005, our Board of Directors authorized us to repurchase up to $500 million of our common stock from time to time through 2006.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2004, our available liquidity was approximately $3.3 billion as illustrated in the table below:

		Amount	Maturity
		(in millions)	
Commercial Paper Backup:			
Lines of Credit	$	1,000	May 2005
Lines of Credit		750	May 2006
Lines of Credit		1,000	May 2007
Letter of Credit Facility		200	September 2006
Total		2,950	
Cash and Cash Equivalents		420	
Total Liquidity Sources		3,370	
Less: AEP Commercial Paper Outstanding		- (a)	
Letters of Credit Outstanding		54	
Net Available Liquidity	$	3,316	

(a) Amount does not include JMG commercial paper outstanding in the amount of $23 million. This commercial paper is specifically associated with the Gavin scrubber and does not reduce AEPs available liquidity. The JMG commercial paper is supported by a separate letter of credit facility not included above.

During the second quarter of 2005, we intend to replace our $1 billion credit facility expiring in May 2005 and our $750 million credit facility expiring in May 2006 with a $1.5 billion five-year credit facility.

Debt Covenants

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and other capital under these covenants is contractually defined. At December 31, 2004, this percentage was 54.1%. Nonperformance of these covenants may result in an event of default under these credit agreements. At December 31, 2004, we complied with the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or those of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the amounts outstanding thereunder payable.

Our revolving credit facilities generally prohibit new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under these facilities if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper.

Under an SEC order, AEP and its utility subsidiaries cannot incur additional indebtedness if the issuers common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts AEP and the utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At December 31, 2004, we were in compliance with this order.

Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC or state commission authorized limits. At December 31, 2004, we had not exceeded the SEC or state commission authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 379 consecutive quarters. The Board of Directors, at its January 2005 meeting, declared a quarterly dividend of $0.35 a share, payable March 10, 2005 to shareholders of record on February 10, 2005. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements as well as financial and other business conditions existing at the time. The timing of any dividend increase could depend upon the resolution of certain issues, including our planned divestitures and the results of our Texas rate and true-up proceedings. We hope to be able to recommend to the Board of Directors gradual, sustainable increases in our common stock dividend from its current level of 35 cents per share per quarter.

PUHCA prohibits our subsidiaries from making loans or advances to the parent company, AEP. In addition, under PUHCA, AEP and its public utility subsidiaries can pay dividends only out of retained or current earnings.

Credit Ratings

We continue to take steps to improve our credit quality, including executing plans during 2004 to further reduce our outstanding debt through the use of proceeds from our asset divestitures and other available cash.

AEPs ratings have not been adjusted by any rating agency during 2004. On August 2, 2004, Moodys Investors Service (Moodys) changed their outlook on AEP to positive from stable, while keeping the remaining rated subsidiaries on stable outlook. The other major rating agencies have AEP and its rated subsidiaries on stable outlook.

Our current credit ratings are as follows:

	Moodys	**S&P**	**Fitch**
AEP Short Term Debt	P-3	A-2	F-2
AEP Senior Unsecured Debt	Baa3	BBB	BBB

If AEP or any of its rated subsidiaries receive an upgrade from any of the rating agencies listed above, our borrowing costs could decrease. If we receive a downgrade in our credit ratings by one of the nationally recognized rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Our cash flows are a major factor in managing and maintaining our liquidity strength.

	2004	**2003**	**2002**
		(in millions)	

Cash and cash equivalents at beginning of period	$ 976	$ 1,084	$ 163
Net Cash Flows From Operating Activities	2,597	2,308	2,067
Net Cash Flows Used For Investing Activities	(376)	(1,979)	(462)
Net Cash Flows Used For Financing Activities	(2,777)	(437)	(681)
Effect of Exchange Rate Changes on Cash	-	-	(3)
Net Increase (Decrease) in Cash and Cash Equivalents	(556)	(108)	921
Cash and cash equivalents at end of period	$ 420	$ 976	$ 1,084

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2004, we had credit facilities totaling $2.8 billion to support our commercial paper program. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC authorized limits.

Operating Activities

	2004	2003	2002
		(in millions)	
Net Income (Loss)	$ 1,089	$ 110	$ (519)
Plus: (Income) Loss From Discontinued Operations	(83)	605	654
Income From Continuing Operations	1,006	715	135
Noncash Items Included in Earnings	1,471	1,939	2,676
Changes in Assets and Liabilities	120	(346)	(744)
Net Cash Flows From Operating Activities	$ 2,597	$ 2,308	$ 2,067

2004 Operating Cash Flow

During 2004, our cash flows from operating activities were $2.6 billion consisting of our income from continuing operations of $1 billion and noncash charges of $1.6 billion for depreciation, amortization and deferred taxes. We recorded $302 million in noncash income for carrying costs on Texas stranded cost recovery and recognized an after tax, noncash extraordinary loss of $121 million to provide for probable disallowances to TCCs stranded generation costs. We realized a $159 million gain on sale of assets primarily on the sales of the IPPs and South Coast. We made a $200 million discretionary contribution to our pension trust.

Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities.

Changes in working capital items resulted in cash from operations of $467 million predominantly due to increased accrued income taxes. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since our consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extension is filed.

2003 Operating Cash Flow

Our cash flows from operating activities were $2.3 billion for 2003. We produced income from continuing operations of $715 million during the period. Income from continuing operations for 2003 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, $193 million for the cumulative effects of accounting changes, and $720 million for impairment losses and other related charges. In addition, there was a current period impact for a net $122 million balance sheet change for risk management contracts that are marked-to-market. These derivative contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The 2003 activity in changes in assets and liabilities relates to a number of items; the most significant of which are:

Noncash wholesale capacity auction true-up revenues resulting in stranded cost regulatory assets of $218 million, which are not recoverable in cash until the conclusion of our TCCs True-up Proceeding.

Net changes in accounts receivable and accounts payable of $269 million related, in large part, to the settlement of risk management positions during 2002 and payments related to those settlements during 2003. These payments include $90 million in settlement of power and gas transactions to the Williams Companies. The earnings effects of substantially all payments were reflected on a MTM basis in earlier periods.

Increases in fuel and inventory levels of $52 million resulting primarily from higher procurement prices.

Reserves for disallowed deferred fuel costs, principally related to Texas, which will be a component of our Texas True-up Proceedings.

2002 Operating Cash Flow

During 2002, our cash flows from operating activities were $2.1 billion. Income from continuing operations was $135 million during the period. Income from continuing operations for 2002 included noncash items of $1.4 billion for depreciation, amortization, and deferred taxes, $350 million related to the cumulative effect of an accounting change, and $639 million for impairment losses. There was a current period impact for a net $275 million balance sheet change for risk management contracts that were marked-to-market. These contracts have unrealized earnings impacts as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts related to the wholesale capacity auction true-up regulatory asset of $262 million, deposits associated with risk management activities of $136 million, and seasonal increases in our fuel inventories.

Investing Activities

	2004	2003	2002
		(in millions)	
Construction Expenditures	$ (1,693)	$ (1,358)	$ (1,685)
Change in Other Cash Deposits, Net	31	(91)	(84)
Proceeds from Sale of Assets	1,357	82	1,263
Other	(71)	(612)	44
Net Cash Flows Used for Investing Activities	$ (376)	$ (1,979)	$ (462)

In 2004, our cash flows used for investing activities were $376 million. We funded our construction expenditures primarily with cash generated by operations. Our construction expenditures of $1.7 billion were distributed across our system, of which the most significant expenditures were investments for environmental improvements of $350 million and for a high voltage transmission line of $75 million. During 2004, we sold our U.K. generation, Jefferson Island Storage, LIG and certain IPP and TCC generation assets and used the proceeds from the sales of these assets to reduce debt.

Our cash flows used for investing activities were $2 billion in 2003 for increased investments in our U.K. operations and environmental and normal capital expenditures.

In 2002, our cash flows used for investing activities were $462 million as the proceeds received from the sales of SEEBOARD, CitiPower, and the Texas REPs offset a significant portion of our construction expenditures.

We forecast $2.7 billion of construction expenditures for 2005. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Financing Activities

	2004	2003	2002
		(in millions)	
Issuances of Equity Securities (common stock/equity units)	$ 17	$ 1,142	$ 990
Issuances/Retirements of Debt, net	(2,229)	(727)	(868)
Retirement of Preferred Stock	(10)	(9)	(10)
Retirement of Minority Interest (a)	-	(225)	-
Dividends Paid on Common Stock	(555)	(618)	(793)
Net Cash Flows Used for Financing Activities	$ (2,777)	$ (437)	$ (681)

(a) Minority Interest was reclassified to debt in July 2003 and the related $525 million of debt was repaid in 2004. See Minority Interest in Finance Subsidiary section of Note 17.

In 2004, we used $2.8 billion of cash to reduce debt and pay common stock dividends. We achieved our goal of reducing debt below 60% of total capitalization by December 31, 2004. The debt reductions were primarily funded by proceeds from our various divestitures in 2004.

Our cash flows used for financing activities were $437 million during 2003. The proceeds from the issuance of common stock were used to reduce outstanding debt and minority interest in a finance subsidiary.

In 2002, we used $681 million of cash from operations to pay common stock dividends and proceeds from the issuance of equity to repay debt.

The following financing activities occurred during 2004 and 2003:

Common Stock:

During 2004 and 2003, we issued 841,732 and 23,001 shares of common stock, respectively, under our incentive compensation plans. For 2004, we received net proceeds of $14 million for525,002 shares. The net proceeds for 2003 were insignificant.

In March 2003, we issued 56 million shares of common stock at $20.95 per share through an equity offering and received net proceeds of $1.1 billion (net of issuance costs of $36 million). We used the proceeds to pay down both short-term and long-term debt with the balance being held in cash.

Debt:

During 2004, we issued approximately $1.2 billion of long-term debt, including approximately $318 million of pollution control revenue bonds. The proceeds of these issuances were used to reduce short-term debt, fund long-term debt maturities and fund optional redemptions. In August 2004, Moodys Investor Services upgraded AEP, Inc.s short-term and long-term debt ratings to a positive outlook.

During 2004, we entered into $530 million notional amount of fixed to floating swaps and unwound $400 million notional amount of swap transactions. The swap unwinds resulted in $9.1 million in cash proceeds. As of December 31, 2004, we had in place interest rate hedge transactions with a notional amount of $515 million in order to hedge a portion of anticipated 2005 issuances.

During 2004, AEP Credit renewed its sale of receivables agreement for three years and it now expires on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

In May 2004, we closed on a $1 billion revolving credit facility for AEP, Inc., which replaced a maturing $750 million revolving credit facility. The facility will expire in May 2007. As of December 31, 2004, we had credit facilities totaling $2.8 billion to support our commercial paper program. As of December 31, 2004, we had no commercial paper outstanding related to the corporate borrowing program. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $661 million in June 2004 and the weighted average interest rate of commercial paper outstanding during the year was 1.81%.

In June 2004, $494 million of five-year floating rate private placement debt was refinanced by Juniper Capital under the lease agreement for our Dow Plaquemine Cogeneration Project. See Power Generation Facility section within this Financial Condition section.

Our plans for 2005 include the following:

In January, APCo issued Senior Unsecured Notes in the amount of $200 million at a rate of 4.95%.

In January, OPCo refinanced $218 million of JMGs Installment Purchase Contracts. The new bonds bear interest at a 35-day auction rate.

In February, TCC reissued $162 million Matagorda County Navigation District Installment Purchase Contracts due May 1, 2030 that were put to TCC in November 2004. These bonds had not been retired as TCC intended to reissue the bonds at a later date. The original installment purchase contracts were mandatory one-year put bonds with fixed rates of 2.15% for Series A and 2.35% for Series B at the time of the put. The reissued contracts bear interest at 35-day auction rates.

In June 2002, we issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note. In May 2005, the senior note portion of the equity will be remarketed and the coupon reset. In August 2005, under the terms of the equity units, holders will be required to purchase from us a certain number of shares per unit (1.2225 shares per unit at our current stock price). This would increase our average total shares outstanding from 396 million in 2004 to an estimated 399 million in 2005.

Quarterly, make discretionary contributions of $100 million to our underfunded pension plans in order to fully fund the plans by the end of 2005.

Minority Interest and Off-balance Sheet Arrangements

We enter into minority interest and off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant minority interest and off-balance sheet arrangements:

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. As managing member, SubOne consolidated Caddis. Steelhead Investors LLC (Steelhead) was an unconsolidated special purpose entity with no relationship to us or any of our subsidiaries. The money invested in Caddis by Steelhead was loaned to SubOne.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis. As a result, a note payable to Caddis was reported as a component of Long-term Debt, the balance of which was $525 million on December 31, 2003. Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.
The $525 million Caddis note payable was paid off in 2004 at which time SubOne no longer had any requirements or obligations under the structure described above.

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies receivables, and accelerate its cash collections.

During 2004, AEP Credit renewed its sale of receivables agreement through August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the future payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Railcars

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. At this time, we intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payment obligations included in the lease footnote. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over time from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2004, the maximum potential loss was approximately $32 million ($21 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payments Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ 1,279	$ 2,921	$ 977	$ 7,161	$ 12,338
Short-term Debt (b)	23	-	-	-	23
Preferred Stock Subject to MandatoryRedemption (c)	66	-	-	-	66
Capital Lease Obligations (d)	64	97	51	92	304
Noncancelable Operating Leases (d)	291	505	452	2,181	3,429
Fuel Purchase Contracts (e)	1,954	2,599	1,111	1,367	7,031
Energy and Capacity Purchase Contracts (f)	188	342	219	507	1,256
Construction Contracts for Capital Assets (g)	626	90	-	-	716
Total	$ 4,491	$ 6,554	$ 2,810	$ 11,308	$ 25,163

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) Represents principal only excluding interest.
(c) See Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries.
(d) See Note 16.
(e) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 11 to the Consolidated Financial Statements, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds, and other commitments. At December 31, 2004, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a)	$ 103	$ 138	$ -	$ 1	$ 242
Guarantees of the Performance of Outside Parties (b)	10	-	22	109	141
Guarantees of our Performance (c)	439	749	681	8	1,877
Transmission Facilities for Third Parties (d)	45	64	20	24	153
Total Commercial Commitments	$ 597	$ 951	$ 723	$ 142	$ 2,413

(a) We have issued standby letters of credit to third parties. These letters of credit cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $242 million with maturities ranging from February 2005 to January 2011. As the parent of all of these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

(b) See Note 8.

(c) We have issued performance guarantees and indemnifications for energy trading, Dow Chemical Companyfinancing,Marine Transportation Pollution Control Bonds and sale agreements.

(d) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Other

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated qualifying cogeneration facility for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease to a total lease term of 30 years. Our lease of the Facility is reported as an owned-asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on our Consolidated Balance Sheets and the obligations under the lease agreement are excluded from the table of future minimum lease payment in Note 16.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing of up to $494 million and equity of up to $31 million from investors with no relationship to AEP or any of AEPs subsidiaries.

The Facility is collateral for Junipers debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Junipers funded obligations as a liability of $520 million. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as $525 million.

We have the right to purchase the Facility for the acquisition cost during the last month of the Juniper Leases initial term or on any monthly rent payment date during any extended term of the lease. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to a nonaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dows rights to lease the Facility or our contract to purchase energy from Dow as described below. If the lease were renewed for up to a 30-year lease term, then at the end of that 30-year term we may further renew the lease at fair market value subject to Junipers approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Junipers acquisition costs, we may be required to make a payment (not to exceed $415 million) to Juniper of the excess of Junipers acquisition cost over the proceeds from the sale. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report Junipers funded obligations related to the Facility on our Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

At December 31, 2004, Junipers acquisition costs for the Facility totaled $520 million, and the total acquisition cost for the completed Facility is currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR (plus a component for a fixed-rate return on Junipers equity investment and an administrative charge). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $23 million represent future minimum lease payments to Juniper during the initial term. The majority of the payment is calculated using the indexed LIBOR rate (2.55% at December 31, 2004). Annual sublease payments received from Dow are approximately $27 million (substantially based on an adjusted three-month LIBOR rate discussed above).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the creation of protocols was not subject to arbitration, but did not rule upon the merits of TEMs claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is in the discovery phase, with trial scheduled to begin on March 23, 2005.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the Commercial Operations Date. Despite OPCos prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCos tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

The uncertainty of the litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by the TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a $258 million ($168 million net of tax) impairment in December 2003. See Power Generation Facility section of Note 10 for further discussion.

Texas REPs

As part of the purchase and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market developed increased earnings opportunities. No revenue was recorded in 2004 or 2003 related to these sharing agreements, pending resolution of various contractual matters. We expect to resolve the outstanding matters and record the related revenue in 2005. Management is unable to predict with certainty the amount of revenue that will be recorded.

SIGNIFICANT FACTORS

Progress Made on Announced Divestitures

We continued with our announced plan to divest noncore components of our nonregulated assets and certain Texas generation assets in order to recover stranded generation costs. During 2004, we generated $1.4 billion in proceeds from these dispositions. See Note 10 of our Notes to Consolidated Financial Statements within this Annual Report.

We made progress on our planned divestiture of certain Texas generation assets by (1) announcing in June 2004 and September 2004 that we had signed agreements to sell TCCs 7.81% share of the Oklaunion Power Station to two nonaffiliated co-owners of the plant for approximately $43 million, subject to closing adjustments, (2) announcing in September 2004 that we had signed agreements to sell TCCs 25.2% share of the STP nuclear plant to two nonaffiliated co-owners of the plant for approximately $333 million, subject to closing adjustments, and (3) closing in July 2004 on the sale of TCCs remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro-electric plant for approximately $428 million, net of adjustments. We expect the sales of Oklaunion and STP to be completed in the first half of 2005. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances or in resolving litigation with a third party affecting Oklaunion which could delay the closings. We will file with the PUCT to recover net stranded costs associated with the sales pursuant to Texas Restructuring Legislation. Stranded costs will be calculated on the basis of all generation assets, not individual plants.

We continue to have discussions with various parties on business alternatives for certain of our other noncore investments, which may result in further dispositions in the future. We are involved in discussions to sell our 50% equity interest in Bajio, a 600 MW natural gas-fired facility in Mexico and our 20% equity interest in Pacific Hydro, an operator of renewable energy facilities in the Pacific Rim.

The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyers proposal. We believe our remaining noncore assets are stated at fair value. However, we may realize losses from operations or losses or gains upon the eventual disposition of these assets that, in the aggregate, could have a material impact on our results of operations, cash flows and financial condition.

Texas Regulatory Activity

Texas Restructuring

Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition.

The Texas Restructuring Legislation, among other things:

provides for the recovery of net stranded generation costs and other generation true-up amounts through securitization and nonbypassable wires charges,

requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
provides for an earnings test for each of the years 1999 through 2001 and,
provides for a stranded cost True-up Proceeding after January 10, 2004.

The True-up Proceedings will determine the amount and recovery of:

net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),

a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCTs excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
final approved deferred fuel balance, and
net carrying costs on true-up amounts.

TCCs recorded net true-up regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.6 billion at December 31, 2004.

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC elected to use the sale of assets method to determine the market value of its generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCCs generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

In December 2003, based on an expected loss from the sale of its generating assets, TCC recognized as a regulatory asset an estimated impairment of approximately $938 million from the sale of all its generation assets. The impairment was computed based on an estimate of TCCs generation assets sales price compared to book basis at December 31, 2003. On July 1, 2004, TCC completed the sale of most of its coal, gas and hydro plants for approximately $428 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. On February 15, 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets. TCC asked the PUCT to rule on the request in April 2005.

On December 17, 2004, the PUCT also issued an Order on Rehearing in the CenterPoint True-Up Proceeding (CenterPoint Order). CenterPoint is a nonaffiliated electric utility in Texas. Among other things, the CenterPoint Order provided certain adjustments to stranded generation plant costs to avoid what the PUCT deemed to be duplicative recovery of stranded costs and the capacity auction true-up amount. The CenterPoint Order also confirmed that stranded costs are to be determined as of December 31, 2001, and identified how carrying costs from that date are to be computed.

In the fourth quarter of 2004, TCC made adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis (instead of December 31, 2003 book basis), including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCCs stranded generation plant costs regulatory asset was reduced by $238 million based on an applicable PUCT duplicate depreciation adjustment in the CenterPoint Order. Theseadjustments are reflected as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in our Consolidated Statements of Operations.

In addition to the two items above (the $938 million impairment in 2003 and the $185 million adjustment in 2004), TCC had recorded $121 million of impairments in 2002 and 2003 on its gas-fired plants. Additionally, other miscellaneous items and the costs to complete the sales, which are still ongoing, of $23 million are included in the recoverable stranded generation plant costs of $897 million.

In the CenterPoint Order, the PUCT specified the manner in which carrying costs should be calculated. In December 2004, TCC computed, based on its interpretation of the methodology contained in the CenterPoint Order, carrying costs of $470 million for the period January 1, 2002 through December 31, 2004 on its stranded generation plant costs net of excess earnings and its wholesale capacity auction true-up regulatory assets at the 11.79% overall pretax cost of capital rate in its UCOS rate proceeding. The embedded 8.12% debt component of the carrying cost of $302 million ($225 million on stranded generation plant costs and $77 million on wholesale capacity auction true-up) was recognized in income in December 2004. This amount is included inCarrying Costs on Texas Stranded Cost Recoveryin our Consolidated Statements of Operations. Of the $302 million recorded in 2004, approximately $109 million, $105 million and $88 million related to the years 2004, 2003 and 2002, respectively. The remaining equity component of $168 million will be recognized in income as collected. TCC will continue to accrue a carrying cost at the rate set forth above until it recovers its approved net true-up regulatory asset. If the PUCT further adjusts TCCs net true-up regulatory asset in TCCs True-up Proceeding, the carrying cost will also be adjusted.

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through nonbypassable transition charges and competition transition charges in the regulated T&D rates. TCC will seek to securitize the approved net stranded generation costs plus related carrying costs. The securitizable portion of this net true-up regulatory asset, which consists of net stranded generation costs plus related carrying costs, was $1.4 billion at December 31, 2004. The other approved net true-up items will be recovered or refunded over time through a nonbypassable competition transition wires charge or credit inclusive of a carrying cost. We expect that TCCs True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net true-up regulatory asset through December 31, 2004. The PUCT will review TCCs filing and determine the amount for the recoverable net true-up regulatory assets.

Due to differences between CenterPoints and TCCs facts and circumstances, the lack of direct applicability of certain portions of the CenterPoint Order to TCC and the unknown nature of future developments in TCCs True-up Proceeding, we cannot, at this time, determine if TCC will incur additional disallowances in its True-up Proceeding. We believe that our recorded net true-up regulatory asset at December 31, 2004 is in compliance with the Texas Restructuring Legislation, and the applicable portions of the CenterPoint Order and other nonaffiliated true-up orders, and we intend to seek vigorously its recovery. If, however, we determine that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from managements interpretation of the Texas Restructuring Legislation and its evaluation of the applicable portions of the CenterPoint and other true-up orders, additional material disallowances are possible.

See TEXAS RESTRUCTURING section of Note 6 for further discussion of Texas Regulatory Activity.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCCs proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%.

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCCs requested $67 million annual rate increase. Their recommendations ranged from a decrease in annual existing rates of approximately $100 million to an increase in TCCs current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a nonunanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCCs rate request from an increase of $67 million to an increase of $41 million.

On July 1, 2004, the ALJswho heard the case issued their recommendations, which included a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded back to the ALJs for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs.

On August 19, 2004, in a separate ruling, the PUCT remanded six other issues to the ALJs requesting revisions to clarify and support the recommendations in the Proposal for Decision (PFD).

The PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCCs calculations, the ALJs recommendations would reduce TCCs annual existing rates between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings.

On November 16, 2004, the ALJs issued their PFD on remand, increasing their recommended annual rate reduction to a range of $51 million to $78 million, depending on the amount disallowed related to affiliated AEPSC billed expenses. At the January 13, 2005 and January 27, 2005 open meetings, the Commissioners considered a number of issues, but deferred resolution of the affiliated AEPSC billed expenses issue, among other less significant issues, until after additional hearings scheduled for early March 2005. Adjusted for the decisions announced by the Commissioners in January 2005, the ALJs' disallowance would yield an annual rate reduction of a range of $48 million to $75 million. If TCC were to prevail on the affiliated expenses issue and all remaining issues, the result would be an annual rate increase of $6 million. When issued, the PUCT order will affect revenues prospectively. An order reducing TCCs rates could have a material adverse effect on future results of operations and cash flows.

Ohio Regulatory Activity

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEPs generation resources that serve Ohio customers. On January 26, 2005, the PUCO approved the plans with some modifications.

The approved plans include annual, fixed increases in the generation component of all customers bills (3% a year for CSPCo and 7% a year for OPCo) in 2006, 2007 and 2008. The plan also includes the opportunity to annually request an additional increase in supply prices averaging up to 4% per year for each company to recover certain new governmentally mandated increased expenditures set out in the approved plan. The plans maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level in effect on December 31, 2005. Such rates could be adjusted with PUCO approval for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion and ancillary services. The approved plans provide for the continued amortization and recovery of stranded transition generation-related regulatory assets. The plans, as modified by the PUCO, require CSPCo and OPCo to allot a combined total of $14 million of previously provided unspent shopping incentives for the benefit of their low-income customers and economic development over the three-year period ending December 31, 2008 which will not have an effect on net income. The plans also authorized each company to establish unavoidable riders applicable to all distribution customers in order to be compensated in 2006 through 2008 for certain new costs incurred in 2004 and 2005 of fulfilling the companies Provider of Last Resort (POLR) obligations. These costs include RTO administrative fees and congestion costs net of financial transmission revenues and carrying cost of environmental capital expenditures. As a result, in 2005, CSPCo and OPCo expect to record regulatory assets of $8 millionand $21 million, respectively, for the subject costs related to 2004 and $14 million and $52 million, respectively, for expected subject costs related to 2005.These regulatory assets, totaling $22 million for CSPCo and $73 million for OPCo, will be amortized as the costs are recovered through POLR riders in 2006 through 2008. The riders, together with the fixed annual increases in generation rates are estimated to provide additional cumulative revenues to CSPCo and OPCo of $190 million and $500 million, respectively, in the three-year period ended December 31, 2008. Other revenue increases may occur related to other provisions of the plans discussed above.

On February 25, 2005, various intervenors filed Applications for Rehearing with the PUCO regarding their approval of the rate stabilization plans. Management expects the PUCO to address the applications before the end of March 2005. Management cannot predict the ultimate impact these proceedings will have on the results of operations and cash flows.

See OHIO RESTRUCTURING section of Note 6 for further discussion of Ohio Regulatory Activity.

Oklahoma Regulatory Activity

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSOs 2001 fuel and purchased power practices. PSO filed testimony in February 2004.

An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $9 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and, if corrected, could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also argued that off-system sales margins were allocated incorrectly. The intervenors reallocation of such margins would reduce PSOs recoverable fuel costsby $7 million for 2000 and $11 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $9 million. The intervenor and the OCC Staff also recommended recalculation of PSOs fuel costs for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. After reviewing the briefs, the ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. In January 2005, the OCC conducted a hearing on the jurisdictional matter and a ruling is expected in the near future. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

PSO Rate Review

In February 2003, the OCC Staff filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC Staffs request. PSOs initial response indicated that its annual revenues were $36 million less than costs. The June 2004 filing updated PSOs request and indicated a $41 million revenue deficiency. As a result, PSO sought OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSOs existing revenues.

In August 2004, PSO filed a motion to amend the timeline to consider new service quality and reliability requirements, which took effect on July 1, 2004. Also in August 2004, the OCC approved a revised schedule. In October 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. In November 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO sought interim approval to collect annual incremental distribution tree trimming costs of approximately $23 million from its customers. Intervenors and the OCC Staff filed testimony recommending that the interim rate relief requested by PSO be modified or denied. The OCC issued an order on PSOs interim request in January 2005, which allows PSO to recover up to an additional $12 million annually for reliability activities beginning in December 2004. Expenses exceeding that amount and the amount currently included in base rates will be considered in the base rate case.

The OCC Staff and intervenors filed testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in January 2005. Their recommendations ranged from a decrease in annual existing rates between $15 million and $36 million. In addition, one party recommended that the OCC require PSO file additional information regarding its natural gas purchasing practices. In the absence of such a filing, this party suggested that $30 million of PSOs natural gas costs not be recovered from customers because it failed to implement a procurement strategy that, according to this party, would have resulted in lower natural gas costs. OCC Staff and intervenors recommended a return on common equity ranging from 9.3% to 10.11%. PSOs rebuttal testimony was filed in February 2005, and that testimony reflects a number of adjustments to PSOs June 2004 updated filing. These adjustments result in a decrease of PSOs revenue deficiency from $41 million to $28 million, although approximately $9 million of that decrease are items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC was expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that we previously recovered from our T&O service customers to mainly AEPs native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP and Exelon filed joint comments and protest with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an orderindicating that the SECA transition rates would be subject to refund or surcharge andset for hearing all remaining aspects of the compliance filings to the November 18 order, including our request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEPs internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or if any increase in the AEP East Companies transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Pension and Postretirement Benefit Plans

We maintain qualified, defined benefit pension plans (Qualified Plans or Pension Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, we have entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees in the U.S.

(Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively the Plans.

The following table shows the net periodic cost (credit) for our Pension Plans and Postretirement Plans:

	2004	2003
	(in millions)	
Net Periodic Cost (Credit):		
Pension Plans	$ 40	$ (3)
Postretirement Plans	141	188
Assumed Rate of Return:		
Pension Plans	8.75 %	9.00 %
Postretirement Plans	8.35 %	8.75 %

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans assets. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our 10-year average return, for the period ended December 2004, of approximately 12%. We anticipate that the investment managers we employ for the Plans will continue to generate long-term returns averaging 8.75%.

The expected long-term rate of return on the Plans assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	2004 Actual Pension Plan Asset Allocation	2004 Actual Postretirement Plan Asset Allocation	2005 Target Asset Allocation	Assumed/Expected Long-term Rate of Return
Equity	68 %	70 %	70 %	10.50 %
Fixed Income	25 %	28 %	28 %	5.00 %
Cash and Cash Equivalents	7 %	2 %	2 %	2.00 %
Total	100 %	100 %	100 %	
Overall Expected Return(weighted average)				8.75 %

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Because of a $200 million discretionary contribution to the Qualified Plans at the end of 2004, the actual asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced back to the target allocation in January 2005. We believe that 8.75% is a reasonable long-term rate of return on the Plans assets despite the recent market volatility. The Plans assets had an actual gain of 13.75% and 23.80% for the twelve months ended December 31, 2004 and 2003, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2004, we had cumulative losses of approximately $30 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, Employers Accounting for Pensions.

The method used to determine the discount rate that we utilize for determining future obligations was revised in 2004. Historically, we based it on the Moodys AA bond index which includes long-term bonds that receive one of the two highest ratings from a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, we changed to a duration based methodin whicha hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AAbond indexwas constructed but with a durationmatching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for the Pension Plans and 5.80% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Plans assets of 8.75%, a discount rate of 5.50% and various other assumptions, we estimate that the pension cost for all pension plans will approximate $55 million, $54 million and $61 million in 2005, 2006 and 2007, respectively. We estimate Postretirement Plan cost will approximate $164 million, $155 million and $146 million in 2005, 2006 and 2007, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 0.5% basis point change to selective actuarial assumptions are in Pension and Other Postretirement Benefits within the Critical Accounting Estimates section of this Managements Financial Discussion and Analysis of Results of Operations.

The value of our Pension Plans assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The Qualified Plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits). The value of our Postretirement Plans assets increased to $1.1 billion at December 31, 2004 from $1.0 billion at December 31, 2003. The Postretirement Plans paid $109 million in benefits to plan participants during 2004.

For our underfunded pension plans, the accumulated benefit obligation in excess of plan assets was $474 million and $445 million at December 31, 2004 and 2003, respectively.

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2004	**2003**
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

We made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intend to make additional discretionary contributions of $100 million per quarter in 2005 to meet our goal of fully funding all qualified pension plans by the end of 2005.

Certain pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that the defined benefit pension plans we sponsor and maintain are in compliance with the applicable requirements of such laws.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of the Federal EPA Complaint and Notice of Violation within Significant Factors - Environmental Matters.

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enrons bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enrons bankruptcy.

Enron Bankruptcy - Bammel storage facility and HPL indemnification matters - In connection with the 2001 acquisition of HPL, we entered into a prepaid arrangement under which we acquired exclusive rights to use and operate the underground Bammel gas storage facility and appurtenant pipelines pursuant to an agreement with BAM Lease Company. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years .

In January 2004, we filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron did not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In April 2004, AEP and Enron entered into a settlement agreement under which we acquired title to the Bammel gas storage facility and related pipeline and compressor assets, plus 10.5 billion cubic feet (BCF) of natural gas currently used as cushion gas for $115 million, which increased our investment in HPL. AEP and Enron agreed to release each other from all claims associated with the Bammel facility, including our indemnity claims. The settlement received Bankruptcy Court approval on September 30, 2004 and closed in November 2004. The parties respective trading claims and Bank of Americas (BOA) purported lien on approximately 55 BCF of natural gas in the Bammel storage reservoir (as described below) are not covered by the settlement agreement.

Enron Bankruptcy - Right to use of cushion gas agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (including the 10.5 BCF described in the preceding paragraph) required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in state court in Texas seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOAs claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enrons financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOAs Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA has objected to the Magistrate Judges decision and the matter is now before the District Judge.

In February 2004, in connection with BOAs dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enrons attempted rejection of these agreements.

On January 26, 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of our 98% interest in HPL against any damages resulting from the BOA litigation. The determination of the amount of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute.

Enron Bankruptcy - Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEPs offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP has asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enrons claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding court-sponsored mediation.

Enron Bankruptcy - Summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and managements analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be physically interconnected and confined to a single area or region. In January 2005, a hearing was held before an ALJ. We expect an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with usand claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million related to previously recorded receivables on which we hold approximately $20 million of credit collateral. We have reserved $4 million against these receivables to reflect the risks of loss, based on the low end of a range of valuations calculated for purposes of the litigation and related mediation. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Coal Transportation Dispute

Certain of our subsidiaries, as joint owners of a generating station have disputed transportation costs billed for coal received between July 2000 and the present time. Our subsidiaries have remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, our subsidiaries recorded a provision for possible loss in December 2004. Of the total provision, a share for deregulated subsidiaries affected income in 2004, a share was recorded as a receivable due to partial ownership of the plant by third parties and the remainder was deferred under the operation of a deferred fuel mechanism. Management continues to work toward mitigating the disputed amounts to the extent possible.

Energy Market Investigations

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and continued to respond to supplemental data requests from some of these agencies in 2003 and 2004.

In September 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC sought civil penalties, restitution and disgorgement of benefits. We responded to the complaint in September 2004. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities, these being all agencies known still to be investigating these matters as to AEP. Our settlements do not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made the settlement payments to the agencies in the first quarter of 2005 in accordance with the respective contractual terms. The agencies have ended their investigations and the CFTC litigation filed in September 2003 has also ended. During 2003 and 2004, we provided for the settlement payments in the amounts of $45 million and $36 million (nondeductible for federal income tax purposes), respectively. We do not expect any impact on 2005 results of operations as a result of these investigations and settlements.

Shareholders Litigation

In 2002, lawsuits alleging securities law violations, a breach of fiduciary duty for failure to establish and maintain adequate internal controls and violations of the Employee Retirement Income Security Act (ERISA) were filed against us, certain executives, members of the Board of Directors and certain investment banking firms. All of these actions except the ERISA claims were dismissed during 2004. We intend to defend vigorously against the remaining ERISA actions. See Note 7 for further discussion.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Management is unable to predict the outcome of these lawsuits but intends to defend vigorously against the claims made in each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against eighteen companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. In December 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint which the Court denied in September 2004. We intend to defend vigorously against these claims.

TEM Litigation

See discussion of TEM litigation within the Financial Condition - Other section of this Managements Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against us and four of our subsidiaries, certain nonaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial courts decision to the United States Court of Appeals for the Fifth Circuit. See Note 7 for further discussion.

Other Litigation

We are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on results of operations, cash flows or financial condition.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that we expect will result in substantial capital investments and operational costs.

The sources of these future requirements include:

Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,

New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
Possible future requirements to reduce carbon dioxide emissions to address concerns about global climate change.

In addition to achieving full compliance with all applicable legal requirements, we strive to go beyond compliance in an effort to be good environmental stewards. For example, we invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. We plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. We have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. We invested over $2 billion, from 1990 through 2004, to equip many of our facilities with pollution control technologies. We will continue to make investments to improve the air emissions from our fossil fuel generating stations as this is the most cost-effective generation source to meet our customers electricity needs.

In 2002, we joined the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program. We committed to reduce or offset approximately 18 million short tons of CO_2 emissions during 2003-2006 below our baseline emissions (i.e. average emission levels during 1998-2001) as adjusted to reflect any changes in our baseline during the commitment period. During 2003, we reduced or offset our emissions byapproximately seven million tons below our voluntary emissions cap and, based on preliminary estimates, we anticipate being below our voluntary emissions cap in 2004.

In August 2004, we released An Assessment of AEPs Actions to Mitigate the Economic Impacts of Emissions Policies. The assessment evaluated our operating emissions control technology, planned investment in additional control equipment and risks associated with an uncertain regulatory environment. It concluded that our actions over the past decade constitute a solid foundation for future efforts to address the intersection between environmental policy and business opportunities. It also concluded that irrespective of the uncertainties surrounding potential air emission regulations and possible future mandatory greenhouse gas regulations, the pollution control investments planned over the next six to eight years are sound. The report also details many of the voluntary actions we are undertaking to limit our greenhouse gas emissions and to develop and/or advance future clean energy technologies.

The Current Air Quality Regulatory Framework

The CAA establishes the federal regulatory authority and oversight for emissions from our fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as national ambient air quality standards (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing nonattainment areas into compliance with the NAAQS. In developing a SIP, each state must demonstrate that attainment areas will maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring nonattainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each states SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to nonattainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NO_x Rule in 1997, which affected 22 eastern states (including states in which AEP operates) and the District of Columbia. The NO_x Rule asked these 23 jurisdictions to adopt requirements for utility and industrial boilers and certain other emission sources to employ cost-effective control technologies to reduce NO_x emissions. The purpose of the request was to reduce the contribution from these 23 jurisdictions to ozone nonattainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NO_x Rule have submitted the required SIP revisions. In response, the Federal EPA approved the SIPs. The compliance date for the SIPs implementing the NO_x Rule and the revised Section 126 Rule was May 31, 2004. These requirements apply to most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality (TCEQ) adopted rules requiring significant reductions in NO_x emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and will begin in May 2005 for SWEPCo.

We installed a variety of emission control technologies to reduce NO_x emissions and to comply with applicable state and federal NO_x requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

Our electric generating units are currently subject to other SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NO_x emissions in certain states. Management believes that our generating plants comply with applicable SIP limits for SO_2, NO_x and particulate matter.

Hazardous Air Pollutants: In the 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPAs 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric generating units are regulated under the NSPS for SO_2, NO_x, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and nonattainment areas.

In attainment areas:

An air quality review must be performed, and

The best available control technology must be employed to reduce new emissions.

In nonattainment areas,

Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and

All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric generating units by approximately 50 percent from the 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers the SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each generating unit surrenders one allowance for each ton of SO_2 that it emits. Emission sources may bank their excess allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NO_x emissions through the use of available combustion controls. Generating units must meet their specific NO_x emission standards or units under common control may participate in an annual averaging program for that group of units.

Future Reduction Requirements for SO_2, NO_x, and Mercury

In 1997, the Federal EPA adopted more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA finalized designations for fine particulate matter nonattainment areas on December 17, 2004. Approximately 200 counties are included in the nonattainment areas including many rural counties in the Eastern United States where our generating units are located. The Federal EPA has not yet issued a rule establishing planning and control requirements or attainment deadlines for these areas. The Federal EPA finalized designations for ozone nonattainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in SIPs to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of nonattainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA has identified SO_2 and NO_x emissions as precursors to the formation of fine particulate matter. NO_x emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NO_x and SO_2 from our generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation is supported by the Bush Administration. This legislation would regulate NO_x, SO_2, and mercury emissions from electric generating plants. We support enactment of a comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. We believe this legislation would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. We believe regulation or legislation will require us to substantially reduce SO_2, NO_x and mercury emissions over the next ten years.

Regulatory Emissions Reductions

In January 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The CAIR would require affected states to include, in their SIPs, a program to reduce NO_x and SO_2 emissions from coal-fired electric utility units. SO_2 and NO_x emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NO_x emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NO_x trading programs were proposed in June 2004.

On April 15, 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include Best Available Retrofit requirements for individual facilities in their SIPs to address regional haze. The guidance applies to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The Federal EPA included an alternative Best Available Retrofit program based on emissions budgeting and trading programs. For generating units that are affected by the CAIR, described above, the Federal EPA proposed that participation in the trading program under the CAIR would satisfy any applicable Best Available Retrofit requirements. However, the guidance preserves the ability of a state to require site-specific installation of pollution control equipment through the SIP for purposes of abating regional haze.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain generating units have achieved comparable levels of mercury reduction by installing conventional SO_2 (scrubbers) and NO_x (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite. The proposed standards for sub-bituminous coals potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NO_x reduction requirements imposed on the same sources under the CAIR. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, which can be used to comply with the more stringent SO_2 and NO_x requirements, have also proven effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register in March 2004. We filed comments on both the initial proposal and the supplemental proposal in June 2004.

The Federal EPAs proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO_2, NO_x and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control. The cost of such facilities could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require us to make significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and may be the subject of a court challenge and further modifications.

All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:

Timing of implementation

Required levels of reductions
Allocation requirements of the new rules, and
Our selected compliance alternatives.

As a result, we cannot estimate our compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to our current investment base and operating cost structure. We intend to seek recovery of these expenditures for pollution control technologies, replacement generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NO_x Compliance

We estimate that we will make future investments of approximately $450 million to comply with the Federal EPAs NO_x Rule, the TCEQ Rule and other final NO_x-related requirements. Approximately $380 million of these investments are expected to be expended during 2005-2007. As of December 31, 2004, we have invested approximately $1.3 billion to comply with various NO_x requirements.

Estimated Investments for SO_2 Compliance

We are complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. We also use SO_2 allowances that we:

Received in the Federal EPAs annual allowance allocation,

Obtained through participation in the annual Federal allowance auction,
Purchased in the market, and
Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, our diminishing SO_2 allowance bank, and increasing allowance prices in the market will require us to install additional controls on certain of our generating units. We plan to install 3,500 MW of additional scrubbers to comply with our Title IV SO_2 obligations. We invested approximately $97 million during 2004. In total, we estimate these additional capital costs to be approximately $1.2 billion, the remainder of which will be expended during 2005-2007.

Estimated Investments to Comply with Future Reduction Requirements

Our planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. We have also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NO_x and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. We estimate that we will invest $1 billion of the capital amount through 2007. We also estimate that we would incur accumulated increases in variable operation and maintenance expenses of $150 million for the periods through 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents.

If the Federal EPAs preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would have higher implementation costs that could be significant. We cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that we operate within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which we are not able to estimate, would be incremental to other cost estimates that we have discussed above.

Between 2010 and 2020, we expect to incur additional costs for pollution control technology retrofits and investment of $1.6 billion. However, the post-2010 capital investment estimates are quite uncertain, reflecting the uncertain nature of future air emission regulatory requirements, technology performance and costs, new pollution control and generating technology developments, among other factors. Associated operation and maintenance expenses for the equipment will also increase during those years. We cannot estimate these additional costs because of the uncertainties associated with the final control requirements and our associated compliance strategy, but these additional costs are expected to be significant.

New Source Review Litigation

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to perfect its complaint in the pending litigation. The NOV expands the number of alleged modifications undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation.

The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, eight Northeastern States filed a separate complaint containing the same allegations against the Conesville and Amos plants that the judge disallowed in the pending case. We filed an answer to the complaint in January 2005.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered from customers.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio SIP occurred at the Stuart Station, and seeking injunctive relief and civil penalties. Stuart Station is jointly-owned by CSPCo (26%) and two nonaffiliated utilities. The owners have filed a motion to dismiss portions of the complaint. We believe the allegations in the complaint are without merit, and intend to defend vigorously against this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions.

On July 19, 2004, the TCEQ issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant, but after investigation determined that further enforcement was not warranted and withdrew the notice on January 5, 2005.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, the volatile organic compound emissions at Pirkey, and the referenced recordkeeping and reporting requirements and heat input value at Welsh. We have submitted additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and nonhazardous materials. We are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. At year-end 2004, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites. There are six additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at seven sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs were attributed to our subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in our electricity prices.

Emergency Release Reporting

Superfund also requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances which cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. The Federal EPA's Complaint seeks an immaterial amount of civil penalties. I&M has requested a hearing and raised several defenses to the claim, including federally permitted release exemption from reporting. Negotiations on the penalty amount are continuing.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCos Gavin Plant SCR system. The Federal EPA indicated their intent to seek civil penalties. In February 2005,OPCoprovided relevant information that the Federal EPA should consider in advance of any filing.

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide (CO_2), which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries legislative bodies is required for it to be enforceable. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countriesand is now in effect as of February 2005.

In August 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the CAA to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

We have been working with the Bush Administration on a voluntary program aimed at meeting the Presidents goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, we have been a leader in pursuing voluntary actions to control greenhouse gas emissions. We expanded our commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program. We made a voluntary commitment to reduce or offset a total of 18 million tons of CO_2 emissions during 2003-2006 as adjusted to reflect any changes in our baseline during the commitment period.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOEs SNF disposal program which is described in the SNF Disposal section of Note 7. Since 1983, I&M has collected $333 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $118 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $215 million to the DOE. TCC has collected and remitted to the DOE, $61 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other nonaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOEs complete failure to perform its contract obligations, and that the utilities suits against DOE may continue in court. In January 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continued on the issue of damages owed to I&M by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against I&M and denied damages. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. As long as the delay in the availability of a government-approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2004, the total decommissioning trust fund balance for Cook Plant was $791 million, which includes earnings on the trust investments. In May 2004, an updated decommissioning study was completed for STP. The study estimates TCCs share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2004, the total decommissioning trust fund for TCCs share of STP was $143 million, which includes earnings on the trust investments. TCC is in the process of selling its ownership interest in STP to two nonaffiliated companies, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, our future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On July 9, 2004, the Federal EPA published in the Federal Register a rule pursuant to the Clean Water Act that will require all large existing, once-through cooled power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plants cooling water intake screen. All plants must reduce fish mortality by 80% to 95%. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. These plants must reduce the rate of smaller organisms passing through the plant by 60% to 90%. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large generating plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance. The estimated capital cost of compliance for our facilities, based on the Federal EPAs analysis in the rule, is $193 million. Any capital costs associated with compliance activities to meet the new performance standards would likely be incurred during the years 2008 through 2010. We have not independently confirmed the accuracy of the Federal EPAs estimate. The rule has provisions to limit compliance costs. We may propose less costly site-specific performance criteria if our compliance cost estimates are significantly greater than the Federal EPAs estimates or greater than the environmental benefits. The rule also allows us to propose mitigation (also called restoration measures) that is less costly and has equivalent or superior environmental benefits than meeting the criteria in whole or in part. Several states, electric utilities (including our APCo subsidiary) and environmental groups appealed certain aspects of the rule. We cannot predict the outcome of the appeals.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, we are managing other environmental concerns which we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made; and
- changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated results of operations or financial condition.

Management has discussed the development and selection of its critical accounting estimates as presented below with the Audit Committee of AEPs Board of Directors and the Audit Committee has reviewed the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

The sections that follow present information about AEPs most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required - Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the passage to our customers through regulated revenues in the same accounting period.

We also record regulatory liabilities for refunds, or probable refunds, to customers that have not yet been made.

Assumptions and Approach Used - When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If it is determined that recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used - A change in the above assumptions may result in a material impact on our results of operations. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition - Unbilled Revenues

Nature of Estimates Required - We recognize and record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is also estimated. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Unbilled revenues included in Revenue were $22 million, $13 million and $7 million, respectively for the years ended December 31, 2004, 2003 and 2002.

Assumptions and Approach Used - The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current months billed KWH plus the prior months unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation determines factors that limit the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are then statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

In addition, an annual comparison to a load research estimate is performed for the East Companies. The annual load research study is an independent unbilled KWH estimate based on a sample of accounts. The unbilled estimate is also adjusted annually for significant differences from the load research estimate.

Effect if Different Assumptions Used - Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1%.

Revenue Recognition - Accounting for Derivative Instruments

Nature of Estimates Required - Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used - We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates based upon the best market information available is somewhat subjective in nature and involves uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings.

We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided for in the original documentation related to hedge accounting.

Effect if Different Assumptions Used - There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified in operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within Quantitative and Qualitative Disclosures About Risk Management Activities.

Long-Lived Assets

Nature of Estimates Required - In accordance with the requirements of SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. These events or circumstances may include the expected ability to recover additional investment in environmental compliance expenditures, the relative pricing of wholesale electricity by region, the anticipated demand and the cost of fuel. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For nonregulated assets, an impairment charge would be recorded as a charge against earnings.

Assumptions and Approach Use - The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales, or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used - In connection with the periodic evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 10, we made our best estimate of fair value using valuation methods based on the most current information at that time. We have been in the process of divesting certain noncore assets and their sales values can vary from the recorded fair value as described in Note 10. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and managements analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required - We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS 87, Employers Accounting For Pensions and SFAS 106, Employers Accounting for Postretirement Benefits Other Than Pensions, respectively. See Note 11 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by our actuaries and us. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

Assumptions and Approach Used - The critical assumptions used in developing the required estimates include the following key factors:

- discount rate
- expected return on plan assets
- health care cost trend rates
- rate of compensation increases

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used - The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		**Other Postretirement Benefits Plans**	
	+0.5%	**-0.5%**	**+0.5%** (in millions)	**-0.5%**
Effect on December 31, 2004 Benefit Obligations:				
Discount Rate	$ (175)	$ 182	$ (133)	$ 142
Salary Scale	11	(11)	4	(4)
Cash Balance Crediting Rate	(20)	20	N/A	N/A
Health Care Trend Rate	N/A	N/A	129	(121)
Expected Return on Assets	N/A	N/A	N/A	N/A
Effect on 2004 Periodic Cost:				
Discount Rate	-	1	(11)	11
Salary Scale	2	(2)	1	(1)
Cash Balance Crediting Rate	3	(3)	N/A	N/A

Health Care Trend Rate	N/A	N/A	19	(18)
Expected Return on Assets	(17)	17	(5)	5

New Accounting Pronouncements

We implemented FASB Staff Position (FSP) FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, effective April 1, 2004, retroactive to January 1, 2004. Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106s 10 percent corridor.

In December 2004, the FASB issued SFAS 123R, Share-Based Payment. SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

We implemented FIN 46R, Consolidated of Variable Interest Entities, effective March 31, 2004 with no material impact to our financial statements. FIN 46R is a revision to FIN 46 which interprets the application of Accounting Research Bulletin No. 51, Consolidated Financial Statements, to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties.

Other Matters

Seasonality

The sale of electric power in our service territories is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of our facilities and the terms when we enter into power contracts. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and may impact cash flows and financial condition.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances, we have certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

We have established policies and procedures which allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, Credit Risk Management, Market Risk Oversight, and senior financial and operating managers.

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO is composed of the chief risk officers of major electricity and gas companies in the United States. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. Implementation of the disclosures is voluntary. We support the work of the CCRO and have embraced the disclosure standards. The following tables provide information on our risk management activities:

Mark-to-Market Risk Management Contract Net Assets (Liabilities)

This table provides detail on changes in our mark-to-market (MTM) net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets (Liabilities)

Year Ended December 31, 2004

(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations (h)	Total
Total MTM Risk Management Contract Net Assets(Liabilities) at December 31, 2003	$ 286	$ 5	$ (246)	$ 45
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(116)	(24)	246	106
Fair Value of New Contracts When Entered During the Period (b)	11	-	-	11
Net Option Premiums Paid/(Received) (c)	(3)	(1)	-	(4)
Change in Fair Value Due to Valuation Methodology Changes (d)	3	-	-	3

Changes in Fair Value of Risk Management Contracts (e)		74		20		(12	)	82
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)		22		-		-		22
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2004	$	277	$	-	$	(12	)	265
Net Cash Flow and Fair Value HedgeContracts (g)								5
Ending Net Risk Management Assets at December 31, 2004							$	270

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized gains from risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) The Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(g) Net Cash Flow and Fair Value Hedge Contracts (pretax) are discussed in detail within the following pages.

(h) During 2004, we began to unwind our risk management contracts within the U.K. as part of our planned divestiture of our UK Operations. We completed the sale of substantially all of our operations and assets in the Investments-UK Operations segment in July 2004 and we expect the remaining MTM Risk Management Current Net Liabilities to be finalized in the first quarter of 2005.

Detail on MTM Risk Management Contract Net Assets (Liabilities)

As of December 31, 2004

(in millions)

	Utility Operations			**Investments-Gas Operations**			**Investments-UK Operations**			**Total**	
Current Assets	$	392	$	255		$	1		$	648	
Noncurrent Assets		354		115			-			469	
Total Assets		746		370			1			1,117	
Current Liabilities		(282	)	(236	)		(11	)		(529	)
Noncurrent Liabilities		(187	)	(134	)		(2	)		(323	)
Total Liabilities		(469	)	(370	)		(13	)		(852	)
Total Net Assets (Liabilities), excluding Hedges	$	277	$	-		$	(12	)	$	265	

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in millions)

	MTM Risk Management Contracts (a)	PLUS: Hedges	Total (b)
Current Assets	$ 648	$ 89	$ 737
Noncurrent Assets	469	1	470
Total MTM Derivative Contract Assets	1,117	90	1,207
Current Liabilities	(529)	(79)	(608)
Noncurrent Liabilities	(323)	(6)	(329)
Total MTM Derivative Contract Liabilities	(852)	(85)	(937)
Total MTM Derivative Contract Net Assets	$ 265	$ 5	$ 270

(a) Does not include Cash Flow and Fair Value Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)

The table presenting maturity and source of fair value of MTM risk management contract net assets (liabilities) provides two fundamental pieces of information.

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets (Liabilities)

Fair Value of Contracts as of December 31, 2004

(in millions)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Utility Operations:							

Prices Actively Quoted - ExchangeTraded Contracts	$ (47)	$ 1	$ 9	$ -	$ -	$ -	$ (37)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	163	44	34	13	-	-	254
Prices Based on Models and Other Valuation Methods (b)	(6)	(8)	2	19	25	28	60
Total	$ 110	$ 37	$ 45	$ 32	$ 25	$ 28	$ 277
Investments - Gas Operations:							
Prices Actively Quoted - ExchangeTraded Contracts	$ 21	$ (4)	$ 2	$ -	$ -	$ -	$ 19
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(4)	(6)	-	-	-	-	(10)
Prices Based on Models and Other Valuation Methods (b)	2	(1)	(1)	(3)	(4)	(2)	(9)
Total	$ 19	$ (11)	$ 1	$ (3)	$ (4)	$ (2)	$ -
Investments - UK Operations:							
Prices Actively Quoted - ExchangeTraded Contracts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(10)	(2)	-	-	-	-	(12)
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$ (10)	$ (2)	$ -	$ -	$ -	$ -	$ (12)
Total:							
Prices Actively Quoted - ExchangeTraded Contracts	$ (26)	$ (3)	$ 11	$ -	$ -	$ -	$ (18)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	149	36	34	13	-	-	232
Prices Based on Models and Other Valuation Methods (b)	(4)	(9)	1	16	21	26	51
Total	$ 119	$ 24	$ 46	$ 29	$ 21	$ 26	$ 265

(a) Prices provided by other external sources - Reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Modeled - In the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.

(c) Amounts exclude Cash Flow and Fair Value Hedges.

The determination of the point at which a market is no longer liquid for placing it in the Modeled category in the preceding table varies by market. The following table reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts

As of December 31, 2004

Commodity	**Transaction Class**	**Market/Region**	**Tenor (in months)**
Natural Gas	Futures	NYMEX/Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Gas East - Northeast, Mid-continent, Gulf Coast, Texas	24

	Swaps	Gas West - Rocky Mountains, West Coast	22
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East - PJM	36
	Physical Forwards	Power East - Cinergy	24
	Physical Forwards	Power East - PJM West	36
	Physical Forwards	Power East - AEP Dayton (PJM)	24
	Physical Forwards	Power East - NEPOOL	12
	Physical Forwards	Power East - NYPP	24
	Physical Forwards	Power East - ERCOT	48
	Physical Forwards	Power East - Com Ed	24
	Physical Forwards	Power East - Entergy	12
	Physical Forwards	Power West - Palo Verde, North Path 15, South Path 15, MidColumbia, Mead	36
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO_2, NO_x	48
Coal	Physical Forwards	PRB, NYMEX, CSX	24

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power and gas operations. We monitor these risks on our future operations and may employ various commodity instruments and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The tables below provide detail on effective cash flow hedges under SFAS 133 included in our Balance Sheets. The data in the first table will indicate the magnitude of SFAS 133 hedges that we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. This table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2003 to December 31, 2004.

Information on energy activities is presented separately from interest rate and foreign currency risk management activities. In accordance with GAAP, all amounts are presented net of related income taxes.

Cash Flow Hedges included in Accumulated Other Comprehensive Loss

On the Balance Sheet as of December 31, 2004

(in millions)

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
Power and Gas	$ 23	$ 26
Foreign Currency	-	-
Interest Rate	(23)	(4)
Total	$ -	$ 22

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in millions)

	Power, Gas and Coal	Foreign Currency	Interest Rate	Total
Beginning Balance, December 31, 2003	$ (65)	$ (20)	$ (9)	$ (94)
Changes in Fair Value (c)	29	-	(21)	8
Reclassifications from AOCI to Net Income (d)	59	20	7	86
Ending Balance, December 31, 2004	$ 23	$ -	$ (23)	$ -

(a) Accumulated Other Comprehensive Income (Loss) After Tax - Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders equity on the balance sheet.

(b) Portion Expected to be Reclassified to Earnings During the Next 12 Months - Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.

(c) Changes in Fair Value - Changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(d) Reclassifications from AOCI to Net Income - Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

Credit Risk

We limit credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moodys Investor Service, Standard and Poors and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. Our analysis, in conjunction with the rating agencies information, is used to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At December 31, 2004, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 14.5%, expressed in terms of net MTM assets and net receivables. The concentration in noninvestment grade credit exposure is proportionately higher due to coal exposures related to domestic MTM coal transactions. These exposures were driven by the continued high levels of prices for coal. As of December 31, 2004, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality		Exposure Before Credit Collateral		Credit Collateral		Net Exposure	Number of Counterparties >10%		Net Exposure of Counterparties >10%
Investment Grade	$	789	$	147	$	642	-	$	-
Split Rating		87		21		66	3		48
Noninvestment Grade		230		134		96	3		68
No External Ratings:									
Internal Investment Grade		161		1		160	3		80
Internal Noninvestment Grade		61		11		50	1		10
Total	$	1,328	$	314	$	1,014	10	$	206

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2007. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. Estimated Plant Output Hedged represents the portion of MWHs of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information

Estimated Next Three Years

As of December 31, 2004

	2005	2006	2007
Estimated Plant Output Hedged	93%	94%	93%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2004, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

VaR Model

December 31, 2004				December 31, 2003			
(in millions)				(in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$19	$5	$1	$11	$19	$7	$4

The 2004 High VaR occurred in January 2004 during a period when international coal and freight prices experienced record high levels and extreme volatility. Within the following month, the VaR returned to levels approaching the average VaR for the year.

Our VaR model results are adjusted using standard statistical treatments to calculate the CCRO VaR reporting metrics listed below.

CCRO VaR Metrics

(in millions)

	December 31, 2004	Average for Year-to-Date 2004	High for Year-to-Date 2004	Low for Year-to-Date 2004
95% Confidence Level, Ten-Day Holding Period	$ 10	$ 20	$ 73	$ 5
99% Confidence Level, One-Day Holding Period	$ 4	$ 8	$ 30	$ 2

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $601 million at December 31, 2004 and $1 billion at December 31, 2003. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or consolidated financial position.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas and to a lesser degree other commodities, principally coal and emissions. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations and our Chief Risk Officer and his staff. When risk management activities exceed certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the Company) as of December 31, 2004 and 2003, and the related consolidated statements of operations, cash flows, and common shareholders equity and comprehensive income (loss), for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Companys internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2005 expressed an unqualified opinion on managements assessment of the effectiveness of the Companys internal control over financial reporting and an unqualified opinion on the effectiveness of the Companys internal control over financial reporting.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 142, Goodwill and Other Intangible Assets, effective January 1, 2002; SFAS 143, Accounting for Asset Retirement Obligations, and EITF 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003; FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003; and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited managements assessment, included in the accompanying *Managements Report on Internal Control Over Financial Reporting* , that American Electric Power Company, Inc. and subsidiary companies (the Company) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Companys 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 managements assessment and an opinion on the effectiveness of the Companys 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 managements 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 opinions.

A companys internal control over financial reporting is a process designed by, or under the supervision of, the companys principal executive and principal financial officers, or persons performing similar functions, and effected by the companys board of directors, management, and other personnel 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 companys 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 companys assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, managements assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal ControlIntegrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal ControlIntegrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and the financial statement schedules as of and for the year ended December 31, 2004 of the Company and our reports dated February 28, 2005 expressed an unqualified opinion on those financial statements and the financial statement schedules and included an explanatory paragraph regarding the Companys adoption of a new accounting pronouncements in 2002, 2003 and 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

MANAGEMENTS REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEPs internal control system was 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.

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.

AEP management assessed the effectiveness of the companys internal control over financial reporting as of December 31, 2004. In making this assessment we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework* . Based on our assessment, the companys internal control over financial reporting was effective as of December 31, 2004.

AEPsindependent registered public accounting firmhas issued an attestation report on our assessment of the Companys internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears above.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2004, 2003 and 2002

(in millions, except per-share amounts)

	2004	2003	2002
REVENUES			
Utility Operations	$ 10,513	$ 10,869	$ 10,446
Gas Operations	3,064	3,099	2,071
Other	480	699	910
TOTAL	14,057	14,667	13,427
EXPENSES			
Fuel for Electric Generation	2,949	3,058	2,580
Purchased Energy for Resale	689	707	532
Purchased Gas for Resale	2,807	2,850	1,946
Maintenance and Other Operation	3,611	3,660	4,054
Asset Impairments and Other Related Charges	-	650	318
Depreciation and Amortization	1,300	1,307	1,356
Taxes Other Than Income Taxes	710	681	718
TOTAL	12,066	12,913	11,504
OPERATING INCOME	1,991	1,754	1,923
Interest Income	33	25	21
Carrying Costs on Texas Stranded Cost Recovery	302	-	-
Investment Value Losses	(15)	(70)	(321)
Gain on Disposition of Equity Investments, Net	153	-	-
Other Income	205	240	321
Other Expense	(183)	(229)	(323)
INTEREST AND OTHER CHARGES			
Interest Expense	781	814	775
Preferred Stock Dividend Requirements of Subsidiaries	6	9	11
Minority Interest in Finance Subsidiary	-	17	35
TOTAL	787	840	821
INCOME BEFORE INCOME TAXES	1,699	880	800
Income Taxes	572	358	315
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	1,127	522	485
DISCONTINUED OPERATIONS, Net of Tax	83	(605)	(654)
EXTRAORDINARY LOSS ON TEXAS STRANDED COSTRECOVERY, Net of Tax	(121)	-	-
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax			
Goodwill and Other Intangible Assets	-	-	(350)
Accounting for Risk Management Contracts	-	(49)	-
Asset Retirement Obligations	-	242	-
NET INCOME (LOSS)	$ 1,089	$ 110	$ (519)
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING	396	385	332
EARNINGS (LOSS) PER SHARE			

Income Before Discontinued Operations, Extraordinary Item and Cumulative Effect ofAccounting Changes	$ 2.85	$ 1.35	$ 1.46
Discontinued Operations	0.21	(1.57)	(1.97)
Extraordinary Loss	(0.31)	-	-
Cumulative Effect of Accounting Changes	-	0.51	(1.06)
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$ 2.75	$ 0.29	$ (1.57)
CASH DIVIDENDS PAID PER SHARE	$ 1.40	$ 1.65	$ 2.40

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in millions)

	2004	2003
CURRENT ASSETS		
Cash and Cash Equivalents	$ 420	$ 976
Other Cash Deposits	175	206
Accounts Receivable:		
Customers	930	1,155
Accrued Unbilled Revenues	592	596
Miscellaneous	79	83
Allowance for Uncollectible Accounts	(77)	(124)
Total Receivables	1,524	1,710
Fuel, Materials and Supplies	852	889
Risk Management Assets	737	766
Margin Deposits	113	119
Other	200	161
TOTAL	4,021	4,827
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,969	15,112
Transmission	6,293	6,130
Distribution	10,280	9,902
Other (including gas, coal mining and nuclear fuel)	3,585	3,590
Construction Work in Progress	1,159	1,287
Total	37,286	36,021
Accumulated Depreciation and Amortization	14,485	14,004
TOTAL - NET	22,801	22,017
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,601	3,582
Securitized Transition Assets	642	689
Spent Nuclear Fuel and Decommissioning Trusts	1,053	982
Investments in Power and Distribution Projects	154	212
Goodwill	76	78
Long-term Risk Management Assets	470	494
Prepaid Pension Obligations	386	-
Other	831	806
TOTAL	7,213	6,843
Assets of Discontinued Operations and Held for Sale	628	3,094
TOTAL ASSETS	$ 34,663	$ 36,781

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

LIABILITIES AND SHAREHOLDERS EQUITY

December 31, 2004 and 2003

			2004	2003
CURRENT LIABILITIES			(in millions)	
Accounts Payable			$ 1,051	$ 1,337
Short-term Debt			23	326
Long-term Debt Due Within One Year (a)			1,279	1,779
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption (a)			66	-
Risk Management Liabilities			608	631
Accrued Taxes			611	620
Accrued Interest			180	207
Customer Deposits			414	379
Other			775	703
TOTAL			5,007	5,982
NONCURRENT LIABILITIES				
Long-term Debt (a)			11,008	12,322
Long-term Risk Management Liabilities			329	335
Deferred Income Taxes			4,819	3,957
Regulatory Liabilities and Deferred Investment Tax Credits			2,540	2,395
Asset Retirement Obligations			827	651
Employee Benefits and Pension Obligations			730	667
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2			166	176
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption (a)			-	76
Deferred Credits and Other			411	409
TOTAL			20,830	20,988
Liabilities of Discontinued Operations and Held for Sale			250	1,876
TOTAL LIABILITIES			26,087	28,846
Cumulative Preferred Stock Not Subject to Mandatory Redemption (a)			61	61
Commitments and Contingencies (Note 7)				
COMMON SHAREHOLDERS EQUITY				
Common Stock Par Value $6.50:				
	2004	**2003**		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	404,858,145	404,016,413		
(8,999,992 shares were held in treasury at December 31, 2004 and 2003)			2,632	2,626
Paid-in Capital			4,203	4,184
Retained Earnings			2,024	1,490
Accumulated Other Comprehensive Income (Loss)			(344)	(426)
TOTAL			8,515	7,874
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY			$ 34,663	$ 36,781

(a) See Accompanying Schedules.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in millions)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income (Loss)	$ 1,089	$ 110	$ (519)
Plus: (Income) Loss from Discontinued Operations	(83)	605	654
Income from Continuing Operations	1,006	715	135
Adjustments for Noncash Items:			
Depreciation and Amortization	1,300	1,307	1,356
Accretion of Asset Retirement Obligations	64	59	-
Deferred Income Taxes	291	163	63
Deferred Investment Tax Credits	(29)	(33)	(31)
Cumulative Effect of Accounting Changes	-	(193)	350
Asset Impairments, Investment Value Losses and Other Related Charges	15	720	639
Carrying Costs on Stranded Cost Recovery	(302)	-	-
Extraordinary Loss	121	-	-
Amortization of Deferred Property Taxes	(3)	(2)	(16)
Amortization of Cook Plant Restart Costs	-	40	40
Mark-to-Market of Risk Management Contracts	14	(122)	275
Pension Contributions	(231)	(58)	-
Over/Under Fuel Recovery	96	239	13
Gain on Sales of Assets	(159)	(48)	(117)
Change in Other Noncurrent Assets	(187)	(137)	(91)
Change in Other Noncurrent Liabilities	134	(171)	(124)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	298	363	(238)
Fuel, Materials and Supplies	33	(52)	(73)
Accounts Payable	(325)	(632)	(21)
Taxes Accrued	427	87	(222)
Customer Deposits	35	194	23
Interest Accrued	-	(5)	72
Other Current Assets	(35)	(5)	65
Other Current Liabilities	34	(121)	(31)
Net Cash Flows From Operating Activities	2,597	2,308	2,067
INVESTING ACTIVITIES			
Construction Expenditures	(1,693)	(1,358)	(1,685)
Change in Other Cash Deposits, Net	31	(91)	(84)
Investment in Discontinued Operations, Net	(59)	(615)	-
Proceeds from Sale of Assets	1,357	82	1,263
Other	(12)	3	44
Net Cash Flows Used For Investing Activities	(376)	(1,979)	(462)
FINANCING ACTIVITIES			
Issuance of Common Stock	17	1,142	656
Issuance of Long-term Debt	682	4,761	2,893
Issuance of Equity Unit Senior Notes	-	-	334
Change in Short-term Debt, Net	(400)	(2,781)	(1,248)
Retirement of Long-term Debt	(2,511)	(2,707)	(2,513)
Retirement of Preferred Stock	(10)	(9)	(10)
Retirement of Minority Interest	-	(225)	-
Dividends Paid on Common Stock	(555)	(618)	(793)

Net Cash Flows Used For Financing Activities	(2,777)	(437)	(681)
Effect of Exchange Rate Change on Cash	-	-	(3)
Net Increase (Decrease) in Cash and Cash Equivalents	(556)	(108)	921
Cash and Cash Equivalents at Beginning of Period	976	1,084	163
Cash and Cash Equivalents at End of Period	$ 420	$ 976	$ 1,084
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	$ (13)	$ (10)	$ (116)
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	13	23	139
Cash and Cash Equivalents from Discontinued Operations - End of Period	$ -	$ 13	$ 23

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS EQUITY AND

COMPREHENSIVE INCOME (LOSS)

(in millions)

	Common Stock				Accumulated Other Comprehensive Income (Loss)	
	Shares	**Amount**	**Paid-in Capital**	**Retained Earnings**		**Total**
DECEMBER 31, 2001	331	$ 2,153	$ 2,906	$ 3,296	$ (126)	$ 8,229
Issuance of Common Stock	17	108	568			676
Common Stock Dividends				(793)		(793)
Common Stock Expense			(30)			(30)
Other			(31)	15		(16)
TOTAL						8,066
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					117	117
Cash Flow Hedges, Net of Tax of $2					(13)	(13)
Securities Available for Sale, Net of Tax of $1					(2)	(2)
Minimum Pension Liability, Net of Tax of $315					(585)	(585)
NET LOSS				(519)		(519)
TOTAL COMPREHENSIVE LOSS						(1,002)
DECEMBER 31, 2002	348	2,261	3,413	1,999	(609)	7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(618)		(618)
Common Stock Expense			(35)			(35)
Other			(6)	(1)		(7)
TOTAL						7,581
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					106	106
Cash Flow Hedges, Net of Tax of $42					(78)	(78)
Securities Available for Sale, Net of Tax of $0					1	1
Minimum Pension Liability, Net of Tax of $75					154	154
NET INCOME				110		110

TOTAL COMPREHENSIVE INCOME						293
DECEMBER 31, 2003	404	2,626	4,184	1,490	(426)	7,874
Issuance of Common Stock	1	6	11			17
Common Stock Dividends				(555)		(555)
Other			8			8
TOTAL COMPREHENSIVE INCOME (LOSS)						7,344
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(104)	(104)
Cash Flow Hedges, Net of Tax of $51					94	94
Minimum Pension Liability, Net of Tax of $52					92	92
NET INCOME				1,089		1,089
TOTAL COMPREHENSIVE INCOME						1,171
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

December 31, 2004 and 2003

December 31, 2004

	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (d)	Amount (in millions)		
Not Subject to Mandatory Redemption:						
4.00% - 5.00%	$102-$110	1,525,903	607,662	$	61	
Subject to Mandatory Redemption:						
5.90% (c)	$100	850,000	182,000 (f)		18	
6.25% - 6.875% (c)	$100	950,000	482,450 (f)		48	
Total Subject to Mandatory Redemption (c)					66	
Total Preferred Stock				$	127	(e)

December 31, 2003

	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (d)	Amount (in millions)		
Not Subject to Mandatory Redemption:						
4.00% - 5.00%	$102-$110	1,525,903	607,940	$	61	
Subject to Mandatory Redemption:						
5.90% - 5.92% (c)	$100	1,950,000	278,100		28	
6.25% - 6.875%(c)	$100	950,000	482,450		48	
Total Subject to Mandatory Redemption (c)					76	
Total Preferred Stock				$	137	(e)

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.

(b) As of December 31, 2004, the subsidiaries had 13,823,127 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,164 shares of no par value preferred stock that were authorized but unissued. As of December 31, 2003, the subsidiaries had 13,780,352 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,768,561 shares of no par value preferred stock that were authorized but unissued.

(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds(generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed.

(d) The number of shares of preferred stock redeemed is 96,378 shares in 2004, 86,210 shares in 2003 and 106,458 shares in 2002.

(e) Due to the implementation of SFAS 150 in July 2003, Cumulative Preferred Stocks of Subsidiaries is no longer presented as one line item on the balance sheet. SFAS 150 has required us to present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a liability. Cumulative Preferred Stocks of Subsidiaries Not Subject to Mandatory Redemption will continue to be reported separately on the balance sheet.

(f) All outstanding shares were redeemed on January 3, 2005.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT

December 31, 2004 and 2003

		Weighted Average	**Interest Rates at December 31,**		**December 31,**	
Maturity		**Interest Rate December 31, 2004**	**2004**	**2003**	**2004**	**2003**
					(in millions)	
FIRST MORTGAGE BONDS (a)						
2004-2008 (b)		6.91%	6.20%-8.00%	6.125%-8.00%	$ 456	$ 694
2024-2025		8.00%	8.00%	6.875%-8.00%	45	246
INSTALLMENT PURCHASE CONTRACTS (c)						
2004-2009		3.58%	1.75%-4.55%	2.15%-6.90%	163	350
2011-2022		3.98%	1.70%-6.10%	1.10%-8.20%	785	943
2023-2038		4.39%	1.125%-6.55%	1.20%-6.55%	825	733
NOTES PAYABLE (d)						
2004-2017		4.98%	2.325%-15.25%	1.537%-15.45%	939	1,518
SENIOR UNSECURED NOTES						
2004-2009		5.22%	2.879%-6.91%	2.43%-7.45%	3,459	3,707
2010-2015		5.30%	4.40%-6.375%	4.40%-6.375%	2,633	2,525
2032-2038		6.32%	5.625%-6.65%	5.625%-7.375%	1,625	1,765
SECURITIZATION BONDS						
2007-2017		5.67%	3.54%-6.25%	3.54%-6.25%	698	746
NOTES PAYABLE TO TRUST						
2037-2043		5.25%	5.25%	5.25%-8.00%	113	331
EQUITY UNIT SENIOR NOTES (e)						
2007		5.75%	5.75%	5.75%	345	345
OTHER LONG-TERM DEBT (f)					243	247
Equity Unit Contract Adjustment Payments	(g)				9	19
Unamortized Discount (net)					(51)	(68)
Total Long-term Debt Outstanding					12,287	14,101
Less Portion Due Within One Year					1,279	1,779
Long-term Portion					$ 11,008	$ 12,322

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment. There are certain limitations on establishing additional liens against our assets under our indentures.

(b) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCCs outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had balances of $84 million and $118 million in 2004 and 2003, respectively. Trust fund assets related to this obligation of $72 million are included in Other Cash Deposits and $22 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at December 31, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.
(c) For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Certain series will bepurchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchaseagreements support certain series.
(d) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(e) In May 2005, the interest rate on these Equity Unit Senior Notes can be reset through a remarketing.
(f) Other long-term debt consists of fair market value of adjustments of fixed rate debt that is hedged, a liability along with accrued interest for disposal of spent nuclear fuel (see Nuclear section of Note 7) and a financing obligation under a sale and leaseback agreement.
(g) The Equity Unit Contract Adjustment Payments settle in August 2005 and as a result the amount is classified as due within one year.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2004 IS PAYABLE AS FOLLOWS:

	2005	2006	2007	2008	2009	After 2009	Total
				(in millions)			
Principal Amount	$ 1,279	$ 1,659	$ 1,262	$ 575	$ 402	$ 7,161	$ 12,338
Unamortized Discount							(51)
							$ 12,287

AMERICAN ELECTRIC POWER, INC. AND SUBSIDIARY COMPANIES

INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Theprincipal business conducted by our eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions. During 2003, we announced plans to significantly restructure and dispose of our nonregulated operations. See Note 10 for a discussion of the impacts of these plans on our organization.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our domestic operations include nonregulated independent power and cogeneration facilities, coal mining and intra-state natural gas operations in Texas. In January 2005, we sold a 98% interest in our natural gas operations in Texas. We sold our natural gas operations in Louisiana in 2004.

We are in the process of completing our divestitures of our noncore assets, including most of our international operations. Our current international portfolio includes only limited investments in the generation and supply of power in Mexico and the Pacific Rim. We sold our generation assets in the U.K. and China in 2004. In 2002, we sold our investments in international distribution companies in Australia and the U.K.

We also conduct domestic barging operations and provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

We are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations. Wholesale power markets are generally market-based and are not cost-based regulated unless a generator/seller of wholesale power is determined by the FERC to have market power. The FERC also regulates transmission service and rates particularly in states that have restructured and unbundled their rates. The state commissions regulate all or portions of our retail operations and retail rates dependent on the status of customer choice in each state jurisdiction (see Note 6).

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially controlled variable interest entities (VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Other Income. We also consolidate variable interest entities in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) Consolidation of Variable Interest Entities (FIN 46R) (see Note 2). We also have generating units that are jointly owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Operations and the investments are reflected in our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, Accounting for the Effects of Certain Types of Regulation, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. We discontinued the application of SFAS 71 for the generation portion of our business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for its West Virginia generation operations and SWEPCo reapplied SFAS 71 for its Arkansas generation operations. SFAS 101, Regulated Enterprises - Accounting for the Discontinuance of Application of FASB Statement No. 71 requires the recognition of an impairment of a regulatory asset arising from the discontinuance of SFAS 71 be classified as an extraordinary item.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, goodwill and intangible asset impairment, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension benefits. The estimates and assumptions used are based upon managements evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the nonregulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses.

We implemented SFAS 143 effective January 1, 2003 (see Accounting for Asset Retirement Obligations (ARO) section of this note).

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets is no longer recoverable or when the assets meet the held for sale criteria under SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Equity investments are required to be tested for impairment when it is determined that an other than temporary loss in value has occurred.

The fair value of an asset and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, generally using composite rates by functional class as follows:

Functional Class of Property		Annual Composite Depreciation Rate Ranges		
		2004	**2003**	**2002**
Production:				
	Steam-Nuclear	3.1%	2.5% to 3.4%	2.5% to 3.4%
	Steam-Fossil-Fired	2.6% to 4.5%	2.3% to 4.6%	2.6% to 4.5%
	Hydroelectric-Conventional and PumpedStorage	2.6% to 3.3%	1.9% to 3.4%	1.9% to 3.4%
Transmission		1.7% to 3.0%	1.7% to 3.1%	1.7% to 3.0%
Distribution		3.2% to 4.1%	3.3% to 4.2%	3.3% to 4.2%
Other		4.9% to 16.4%	5.2% to 16.7%	4.7% to 9.9%

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs were $0.65 per ton in 2004, $0.25 per ton in 2003 and $0.32 per ton in 2002. In 2004, average amortizations rates increased from 2003 due to a lower tonnage nomination from the power plant yielding a higher cost per ton. In addition, coal mining assets amortized at a lower rate were sold in 2004. In 2002, certain coal-mining assets were impaired by $60 million leading to the decline in amortization rates in 2003.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are debited to accumulated depreciation. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred (see Accounting for Asset Retirement Obligations (ARO) section of this note).

Accounting for Asset Retirement Obligations (ARO)

We implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. ARO accounting is being followed for regulated and nonregulated property that has a legal removal obligation. Upon removal of ARO property, any difference between the ARO accrual and actual removal costs is recognized as income or expense. The following is a reconciliation of 2003 and 2004 aggregate carrying amount of asset retirement obligations:

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Mining Operations	Total
		(in millions)		
ARO Liability at January 1, 2003 Including Held for Sale	$ 718.3	$ 69.8	$ 37.2	$ 825.3
Accretion Expense	52.6	5.6	2.3	60.5
Liabilities Incurred	-	-	8.3	8.3
Foreign Currency Translation	-	-	5.3	5.3
ARO Liability atDecember 31, 2003 Including Held for Sale	770.9	75.4	53.1	899.4
Less ARO LiabilityHeld for Sale:				

South Texas Project (b)		(218.8	)		-			-			(218.8	)
U.K. Plants					-			(28.8	)		(28.8	)
ARO Liability atDecember 31, 2003	$	552.1		$	75.4		$	24.3		$	651.8	
ARO Liability at January 1, 2004 Including Held for Sale	$	770.9		$	75.4		$	53.1		$	899.4	
Accretion Expense		56.5			6.0			2.8			65.3	
Foreign Currency Translation		-			-			0.6			0.6	
Liabilities Incurred		-			-			17.7			17.7	
Liabilities Settled (a)		-			(0.4	)		(56.9	)		(57.3	)
Revisions in Cash Flow Estimates		132.1			3.2			15.0			150.3	
ARO Liability atDecember 31, 2004 Including Held for Sale		959.5			84.2			32.3			1,076.0	
Less ARO Liability Held for Sale: South Texas Project (b)		(248.9	)		-			-			(248.9	)
ARO Liability atDecember 31, 2004	$	710.6		$	84.2		$	32.3		$	827.1	

(a) Liabilities settled include approximately $45.5 million in noncash reductions of ARO associated with the sale of the U.K. generation assets in July 2004.

(b) We have signed an agreement to sell TCCs share of South Texas Project (see Note 10).

Accretion expense is included in Maintenance and Other Operation expense in our accompanying Consolidated Statements of Operations.

As of December 31, 2004 and 2003, the fair values of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $934 million and $845 million, respectively, of which $791 million and $720 million relating to the Cook Plant are recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair values of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for the South Texas Project totaling $143 million and $125 million as of December 31, 2004 and 2003, respectively, are classified as Assets of Discontinued Operations and Held for Sale in our Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the year ended December 31, 2002 because the pro forma application of SFAS 143 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during that period.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations, interest is capitalized during construction in accordance with SFAS 34, Capitalization of Interest Costs. Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were $37 million, $37 million and $34 million in 2004, 2003 and 2002, respectively.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt.

Inventory

Except for PSO and TNC, the domestic utility companies value fossil fuel inventories at the lower of a weighted average cost or market. PSO and TNC record fossil fuel inventories at the lower of cost or market, utilizing the LIFO cost method. Materials and supplies inventories are carried at average cost. Gas inventory is carried at the lower of weighted average cost or market. During 2003, a fair value hedging strategy was implemented for certain gas inventory. Changes in the fair value of hedged inventory were recorded to the extent offsetting hedges are designated against that inventory. In the third quarter of 2004, the fair value hedges were de-designated. As a result, the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power and gas sales when we deliver power or gas to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit, Inc. factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCos accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, allowing the receivables to be removed from the companys balance sheets (see Sale of Receivables section of Note 17).

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. that are included in our consolidated financial statements and investments outside the U.S. that are accounted for under the equity method are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52, Foreign Currency Translation. Although the effects of foreign currency fluctuations are mitigated by the fact that expenses of foreign subsidiaries are generally incurred in the same currencies in which sales are generated, the reported results of operations of our foreign subsidiaries are affected by changes in foreign currency exchange rates and, as compared to prior periods, will be higher or lower depending upon a weakening or strengthening of the U.S. dollar. Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The balance of Accumulated Other Comprehensive Income as of December 31, 2004 has been reduced significantly primarily due to the disposition of our U.K. assets in 2004, which is reflected in Discontinued Operations on our Consolidated Statements of Operations. The impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates, is shown on our Consolidated Statements of Cash Flows in Effect of Exchange Rate Change on Cash. Actual currency transaction gains and losses are recorded in income when they occur.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulators review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. Whena fuel cost disallowancebecomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4).

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with ratepayers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze ended on March 1, 2004. Through subsequent orders, the Indiana Utility Regulatory Commission (IURC) has authorized the billing of capped fuel rates on an interim basis until April 1, 2005. In Indiana, there is an issue as to whether the freeze should be extended through 2007 under an existing corporate separation stipulation agreement. Management disagrees with this interpretation of the stipulation and the matter is pending resolution. In West Virginia, the fuel clause is suspended indefinitely. Changes in fuel costs also impact earnings for certain of our IPP generating units that do not have long-term contracts for their fuel supply or have not hedged fuel costs (see Notes 4 and 6).

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets also reduces future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase and sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Beginning in July 2004, as a result of the sale of generation assets in AEP's west zone, we are short capacity and must purchase physical power to supply retail and wholesale customers. For power purchased under derivative contracts in AEPs west zone, prior to settlement the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period are recognized as Revenues. If the contract results in the physical delivery of power, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded gross as Purchased Energy for Resale. If the contract does not physically deliver, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded as Revenues in the Consolidated Statement of Operations on a net basis (see Note 14).

Domestic Gas Pipeline and Storage Activities

Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and accounted for using MTM accounting (resale gas contracts). The unrealized and realized gains and losses on resale gas contracts for the sale of natural gas are presented as Revenues in the Consolidated Statement of Operations. The unrealized and realized gains and losses on physically settled resale gas contracts for the purchase of natural gas are presented as Purchased Gas for Resale in the Consolidated Statement of Operations (see Note 14).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities. Effective October 2002, these activities were focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, we recorded wholesale marketing and risk management activities using the MTM method of accounting.

In October 2002, EITF 02-3 precluded MTM accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all nonderivative wholesale and risk management transactions occurring on or after October 25, 2002. For nonderivative risk management transactions entered prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change (see Accounting for Risk Management Contracts section of Note 2).

After January 1, 2003, revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in Revenues in the Consolidated Statement of Operations on a net basis. In jurisdictions subject to cost-based regulation, the unrelated MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).Where they are included in cost-based regulated rates on a realized basis, the MTM gains and losses are deferred as regulatory assets or liabilities.

Certain wholesale marketing and risk management transactions are designated as a hedge of a forecasted transaction, a future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivatives gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 14).

Construction Projects for Outside Parties

We engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred and billed to the outside party.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that we will recover specifically incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. Maintenance costs during refueling outages at the Cook Nuclear Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

Other Income and Other Expense

Nonoperational revenue including the nonregulated business activities of our utilities, equity earnings of nonconsolidated subsidiaries, gains on dispositions of property, AFUDC-equity and miscellaneous income, are reported in Other Income. Nonoperational expenses including nonregulated business activities of our utilities, losses on dispositions of property, miscellaneous amortization, donations and various other nonrecoverable/nonoperating and miscellaneous expenses, are reported in Other Expense.

AEP Consolidated Other Income and Other Expense:

	December 31,		
	2004	**2003**	**2002**
		(in millions)	
Other Income:			
Equity Earnings (Loss)	$ 18	$ 10	$ (15)
Nonutility Revenue	127	129	201
Gain on Sale of REPs (Mutual Energy Companies)	-	39	129
Other	60	62	6
Total Other Income	$ 205	$ 240	$ 321
Other Expense:			
Nonutility Expense	$ 103	$ 112	$ 179
Property and Miscellaneous Taxes	20	20	20
Other	60	97	124
Total Other Expense	$ 183	$ 229	$ 323

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customer. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The amortization expense is included in interest charges.

We classify instruments that have an unconditional obligation requiring us to redeem the instruments by transferring an asset at a specified date as liabilities on our Consolidated Balance Sheets. Those instruments consist of Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as of December 31, 2004 and 2003. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Expense. In accordance with SFAS 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, dividends from prior periods remain classified as preferred stock dividends, a component of Preferred Stock Dividend Requirements of Subsidiaries, on our Consolidated Statements of Operations.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of any assets including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. Purchased goodwill and intangible assets with indefinite lives are not amortized. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. Goodwill is tested at the reporting unit level and other intangibles are tested at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods. Intangible assets with finite lives are amortized over their respective estimated lives, currently ranging from 5 to 10 years, to their estimated residual values.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

acceptable investments (rated investment grade or above);

maximum percentage invested in a specific type of investment;
prohibition of investment in obligations of the applicable company or its affiliates; and
withdrawals only for payment of decommissioning costs and trust expenses.

Trust funds are maintained for each regulatory jurisdiction and managed by external investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Spent Nuclear Fuel and Decommissioning Trusts for amounts relating to the Cook Plant and are included in Assets of Discontinued Operations and Held for Sale for amounts relating to STP (see Assets Held for Sale section of Note 10). These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the common shareholders equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

	December 31,	
	2004	**2003**
Components	**(in millions)**	
Foreign Currency Translation Adjustments, net of tax	$ 6	$ 110
Securities Available for Sale, net of tax	(1)	(1)
Cash Flow Hedges, net of tax	-	(94)
Minimum Pension Liability, net of tax	(349)	(441)
Total	$ (344)	$ (426)

Stock-Based Compensation Plans

At December 31, 2004, we have two stock-based employee compensation plans with outstanding stock options (see Note 12). No stock option expense is reflected in our earnings, as all options granted under these plans had exercise prices equal to or above the market value of the underlying common stock on the date of grant.

We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees, as well as stock units to nonemployee members of our Board of Directors. The Deferred Compensation and Stock Plan for Non-Employee Directors permits directors to choose to defer up to 100 percent of their annual Board retainer in stock units, and the Stock Unit Accumulation Plan for Non-Employee Directors awards stock units to directors. Compensation cost is included in Net Income (Loss) for the performance share units, phantom stock units, restricted shares, restricted stock units and the Directors stock units.

The following table shows the effect on our Net Income (Loss) and Earnings (Loss) per Share as if we had applied fair value measurement and recognition provisions of SFAS 123, Accounting for Stock-Based Compensation, to stock-based employee compensation awards:

	Year Ended December 31,		
	2004	2003	2002
	(in millions, except per share data)		
Net Income (Loss), as reported	$ 1,089	$ 110	$ (519)
Add: Stock-based compensation expense included in reported net income (loss), net of related tax effects	15	2	(5)
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(18)	(7)	(4)
Pro Forma Net Income (Loss)	$ 1,086	$ 105	$ (528)
Earnings (Loss) per Share:			
Basic - As Reported	$ 2.75	$ 0.29	$ (1.57)
Basic - Pro Forma (a)	$ 2.74	$ 0.27	$ (1.59)
Diluted - As Reported	$ 2.75	$ 0.29	$ (1.57)
Diluted - Pro Forma (a)	$ 2.74	$ 0.27	$ (1.59)

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

Basic earnings (loss) per common share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards. The effects of stock options have not been included in the fiscal 2002 diluted loss per common share calculation as their effect would have been antidilutive.

The calculation of our basic and diluted earnings (loss) per common share (EPS) is based on weighted average common shares shown in the table below:

	2004	2003	2002
		(in millions)	
Weighted Average Shares:			
Average Common Shares Outstanding	396	385	332
Assumed Conversion of Dilutive Stock Options (see Note 12)	-	-	-
Diluted Average Common SharesOutstanding	396	385	332

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share. Our basic and diluted EPS are the same in 2004, 2003 and 2002 since the effect on weighted average common shares outstanding is minimal.

Had we reported net income in fiscal 2002, incremental shares attributable to the assumed exercise of outstanding stock options would have increased diluted common shares outstanding by 398,000 shares.

Options to purchase 5.2 million, 5.6 million and 8.8 million shares of common stock were outstanding at December 31, 2004, 2003 and 2002, respectively, but were not included in the computation of diluted earnings per share because the options exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

In addition, there is no effect on diluted earnings per share related to our equity units (issued in 2002) unless the market value of our common stock exceeds $49.08 per share. There were no dilutive effects from equity units at December 31, 2004, 2003 and 2002. If our common stock value exceeds $49.08 we would apply the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contracts are used to repurchase outstanding shares (see Equity Units section of Note 17).

Supplementary Information

	Year Ended December 31,		
	2004	2003	2002
Related Party Transactions		(in millions)	
AEP Consolidated Purchased Power - Ohio Valley ElectricCorporation (44.2% owned by AEP)	$ 161	$ 147	$ 142
AEP Consolidated Other Revenues - barging and othertransportation services - Ohio Valley Electric Corporation(44.2% owned by AEP)	14	9	-
Cash Flow Information			
Cash was paid (received) for:			
Interest (net of capitalized amounts)	755	741	792
Income Taxes	(107)	163	336
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	120	25	6
Assumption (Disposition) of Liabilities Related toAcquisitions/Divestitures	(67)	-	1
Increase in assets and liabilities resulting from:			
Consolidation of VIEs due to the adoption of FIN 46	-	547	-
Consolidation of merchant power generation facility	-	496	-

Power Projects

We own a 50% interest in a domestic unregulated power plant with a capacity of 450 MW located in Texas and an international power plant totaling 600 MW located in Mexico (see Note 10).

We account for investments in power projects that are 50% or less owned using the equity method and report them as Investments in Power and Distribution Projects on our Consolidated Balance Sheets (see Eastex section in Note 10). At December 31, 2004, the 50% owned domestic power project and international power investment are accounted for under the equity method and have unrelated third-party partners. The domestic project is a combined cycle gas turbine that provides steam to a host commercial customer and is considered a Qualifying Facility (QF) under PURPA. The international power investment is classified as a Foreign Utility Company (FUCO) under the Energy Policies Act of 1992.

Both the international and domestic power projects have project-level financing, which is nonrecourse to AEP. In addition, for the international project, AEP has guaranteed $57 million of letters of credit associated with the financing and a $10 million letter of credit for the benefit of the power purchaser under the power supply contract.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2004 that we have determined relate to our operations.

FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

We implemented FASB Staff Position (FSP) FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which we previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106s 10 percent corridor. See Note 11 for additional information related to the effects of implementation of FAS 106-2 on our postretirement benefit plans.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, Share-Based Payment. SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25. The statement is effective as of the first interim or annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement.

We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

SFAS 153 Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29

In December 2004, the FASB issued SFAS 153, Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29 to eliminate the Opinion 29 exception to fair value for nonmonetary exchanges of similar productive assets and to replace it with a general exception for exchange transactions that do not have commercial substance. We expect to implement SFAS 153 prospectively, beginning July 1, 2005. We do not expect the effect to be material to our results of operations, cash flows or financial condition.

FIN 46 (revised December 2003)Consolidation of Variable Interest Entities and FIN 46 Consolidation of Variable Interest Entities

We implemented FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, Consolidated Financial Statements, to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated Caddis Partners, LLC (Caddis) and we also deconsolidated the trusts which hold mandatorily redeemable trust preferred securities (see Minority Interest in Finance Subsidiary and Trust Preferred Securities sections of Note 17).

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Also, after consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabines revenues against SWEPCos fuel expenses. There is no cumulative effect of accounting change recorded as a result of the requirement to consolidate, and there was no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG, an entity formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMGs revenues against OPCos operating lease expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG (see Gavin Scrubber Financing Agreement section of Note 16).

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. We implemented FIN 46R effective March 31, 2004 with no material impact to our financial statements.

EITF Issue 03-13 Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations

This issue developed a model for evaluating which cash flows are to be considered in determining whether cash flows have been or will be eliminated and what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We will apply this issue to components that are disposed of or classified as held for sale in periods beginning after December 15, 2004.

FASB Staff Position 109-1 Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Activities Provided by the American Jobs Creation Act of 2004

On October 22, 2004, the American Jobs Creation Act of 2004 (Act) was signed into law. The Act included tax relief for domestic manufacturers (including the production, but not the delivery of electricity) by providing a tax deduction up to 9 percent (when fully phased-in in 2010) on a percentage of qualified production activities income. Beginning in 2005 and for 2006, the deduction is 3 percent of qualified production activities income. The deduction increases to 6 percent for 2007, 2008 and 2009. The FASB staff has indicated that this tax relief should be treated as a special deduction and not as a tax rate reduction. While the U.S. Treasury has issued general guidance on the calculation of the deduction, this guidance lacks clarity as to determination of qualified production activities income as it relates to utility operations. We believe that the special deduction for 2005 and 2006 will not materially affect our results of operations, cash flows, or financial condition.

Future Accounting Changes

The FASBs standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, asset retirement obligations, fair value measurements, business combinations, revenue recognition, pension plans, liabilities and equity, earnings per share calculations, accounting changes and related tax impacts as applicable. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

EXTRAORDINARY ITEM

In the fourth quarter of 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis, including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCCs stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in the CenterPoint Order (see Wholesale Capacity Auction True-up section of Note 6). These net adjustments were recorded as an extraordinary item in accordance with SFAS 101 and are reflected in our Consolidated Statements of Operations as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10, Accounting for Contracts Included in Energy Trading and Risk Management Activities, and related interpretive guidance. We recorded a $49 million after tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in the first quarter of 2003 ($13 million in Utility Operations, $22 million in Investments - Gas Operations and $14 million in Investments - UK Operations segments). These amounts are recognized as the positions settle.

Asset Retirement Obligations

In the first quarter of 2003, we recorded $242 million of after tax income as a cumulative effect of accounting change for Asset Retirement Obligations in accordance with SFAS 143 ($249 million after tax income in Utility Operations and $7 million after tax loss in Investments-UK Operations segment).

Goodwill and Other Intangible Assets

SFAS 142, Goodwill and Other Intangible Assets, requires that goodwill and intangible assets with indefinite useful lives no longer be amortized and be tested annually for impairment. The implementation of SFAS 142 in 2002 resulted in a $350 million net transitional loss for our U.K. and Australian operations (included in the Investments - Other segment) and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change (see Note 3).

See table below for details of the Cumulative Effect of Accounting Changes:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Accounting for Risk Management Contracts (EITF 02-3)	$ -	$ (49)(a)	$ -
Asset Retirement Obligations (SFAS 143)	-	242 (b)	-
Goodwill and Other Intangible Assets (SFAS 142)	-	-	(350)(c)
Total	$ -	$ 193	$ (350)

(a) net of tax of $19 million

(b) net of tax of $157 million
(c) net of tax of $0

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2004 and 2003 by operating segment are:

		Investments			
	Utility Operations	Gas Operations	UK Operations	Other	AEP Consolidated
			(in millions)		
Balance at January 1, 2003	$ 37.1	$ 306.3	$ 11.2	$ 41.4	$ 396.0
Impairment losses (a)	-	(291.4)	(12.2)	-	(303.6)
Assets Held for Sale, Net (b)	-	(14.9)	-	-	(14.9)
Foreign currency exchange rate changes	-	-	1.0	-	1.0
Balance at December 31, 2003	$ 37.1	$ -	$ -	$ 41.4	$ 78.5
Balance at January 1, 2004	$ 37.1	$ -	$ -	$ 41.4	$ 78.5
Goodwill written off related to sale of Numanco	-	-	-	(2.6)	(2.6)
Balance at December 31, 2004	$ 37.1	$ -	$ -	$ 38.8	$ 75.9

(a) Impairment Losses: (see Note 10)

2003

Gas Operations

In the fourth quarter of 2003, we prepared our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. As a result of the tests, we recognized a $162.5 million goodwill impairment loss related to HPL ($150.4 million) and AEPES ($12.1 million).

Also during 2003, we recognized a goodwill impairment loss of $128.9 million related to Jefferson Island.

UK Operations

In 2003, we recognized a goodwill impairment loss of $12.2 million related to UK Coal Trading.

2004

In the fourth quarter of 2004, we prepared our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses.

(b) On our Consolidated Balance Sheets, amounts related to entities classified as held for sale are excluded from Goodwill and are reported within Assets of Discontinued Operations and Held for Sale until they are sold (see Note 10). The following entities were classified as held for sale and had goodwill impairments for the year ended December 31, 2003:

Jefferson Island (Investments - Gas Operations segment) - $14.4 million balance in goodwill at December 31, 2003.

LIG Chemical (Investments - Gas Operations segment) - $0.5 million balance in goodwill at December 31, 2003.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are $29.7 million at December 31, 2004 and $34.1 million at December 31, 2003, net of accumulated amortization and are included in Other Noncurrent Assets on the Consolidated Balance Sheets. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

		December 31, 2004		December 31, 2003	
	Amortization Life	**Gross Carrying Amount**	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
	(in years)	**(in millions)**		**(in millions)**	
Software acquired (a)	3	$ -	$ -	$ 0.5	$ 0.3
Patent	5	0.1	0.1	0.1	-
Easements	10	2.2	0.5	2.2	0.3
Trade name and administration of contracts	7	2.4	0.9	2.4	0.9
Purchased technology	10	10.9	3.2	10.9	2.2
Advanced royalties	10	29.4	10.6	29.4	7.7
Total		$ 45.0	$ 15.3	$ 45.5	$ 11.4

(a) This asset related to U.K. Generation Plants and was sold during the third quarter of 2004.

Amortization of intangible assets was $4 million, $5 million and $4 million for 2004, 2003 and 2002, respectively. Our estimated total amortization is $5 million for each year 2005 through 2007, $4 million for 2008 through 2010 and $3 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to the Nuclear Plant Restart and the Merger with CSW.

TNC Fuel Reconciliations

In 2002, TNC filed with the PUCT to reconcile fuel costs and defer the unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in its True-up Proceeding. As a result of the introduction of customer choice on January 1, 2002, this fuel reconciliation for the period from July 2000 through December 2001 is the final fuel reconciliation for TNCs ERCOT service territory.

Through 2004, TNC provided $30 million for various disallowances recommended by the ALJ and accepted by the PUCT in open session of which $20 million was recorded in 2003 and $10 million in 2004. On October 18, 2004, the PUCT issued a final order which concluded that the over-recovery balance was $4 million. TNC has fully provided for the PUCTs final order in this proceeding. TNC has sought declaratory and injunctive relief in Federal District Court for $8 million of its provision resulting from the PUCTs rejection of TNCs application of a FERC-approved tariff on the basis that the interpretation of the tariff is within the exclusive jurisdiction of the FERC and not the PUCT. TNC has also appealed various other issues to state District Court in Travis County for which it has provided $22 million. Another party has also filed a state court appeal. TNC will pursue vigorously these proceedings but at present cannot predict their outcome.

In February 2002, TNC received a final PUCT order in a previous fuel reconciliation covering the period July 1997 through June 2000 and reflected the order in its financial statements. In September 2004, that decision was affirmed by the Third Court of Appeals. No appeal was filed with the Supreme Court of Texas.

TCC Fuel Reconciliation

In 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in its True-up Proceeding. This reconciliation covers the period from July 1998 through December 2001.

On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million of eligible fuel costs. In May 2004, the PUCT accepted most of the ALJs recommendations in the TCC case, however, the PUCT rejected the ALJs recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy-only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues. In testimony filed in the remand proceeding, TCC asserted that its energy-only purchased power contracts do not include any capacity component. Intervenors, including the Office of Public Utility Counsel (OPC), have filed testimony recommending that $15 million to $30 million of TCCs purchased power costs reflect capacity costs which are not recoverable in the fuel reconciliation. The ALJ issued a report on January 13, 2005 on the imputed capacity remand recommending that specified energy-only purchased power contracts include a capacity component with a value of $2 million. At its February 24, 2005 open meeting, the PUCT reviewed the ALJ report and also ruled that specified energy-only purchased power contracts include a capacity component of $2 million. As a result of the PUCTs acceptance of most of the ALJs recommendations in TCCs case and the PUCTs rejection in the TNC case of our interpretation of its FERC tariff, TCC has recorded provisions totaling $143 million, with $81 million provided in 2003 and $62 million in 2004. The over-recovery balance and the provisions for probable disallowances totaled $212 million including interest at December 31, 2004.

Management believesthey havematerially provided for probable to-date disallowances in TCCs final fuel reconciliation pending receipt of a final order. A final order has not yet been issued in TCCs final fuel reconciliation.A n order from the PUCT, disallowing amounts in excess of the established provision, could have a material adverse effect on future results of operations and cash flows. We will continue to challenge adverse decisions vigorously, including appeals and challenges in Federal Court if necessary. Additional information regarding the True-up Proceeding for TCC can be found in Note 6.

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period from January 2000 through December 2002. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation proceeding. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In April 2004, the PUCT approved the settlement.

SWEPCo Fuel Factor Increase

On November 5, 2004, SWEPCo filed a petition with the PUCT to increase its annual fixed fuel factor by $29 million. SWEPCo and the various parties to the proceedings reached a settlement effective January 31, 2005 that increases its annual fixed fuel factor revenues by approximately $25 million or approximately 18% over the amount that would be collected by the fuel factors currently in effect. The settlement agreement was approved by the PUCT on January 31, 2005. Actual fuel costs will be subject to review and approval in a future fuel reconciliation.

SWEPCo Louisiana Fuel Audit

The Louisiana Public Service Commission (LPSC) is performing an audit of SWEPCos historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has overcharged them for fuel costs since 1975. The LPSC consolidated the customer complaints and audit. In testimony filed in this matter, the LPSC Staff recommended refunds of approximately $5 million. Subsequently, surrebuttal testimony filed by the LPSC Staff recognized that SWEPCos costs were reasonable and that most costs could be recovered through the fuel adjustment clause pending LPSC approval. While initial indications from the LPSC Staff surrebuttal testimony would not indicate a material disallowance, management cannot predict the ultimate outcome in this proceeding. If the LPSC or the Court does not agree with LPSC Staff recommendations, it could have an adverse effect on future results of operations and cash flows.

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSOs 2001 fuel and purchased power practices. PSO filed testimony in February 2004.

An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $9 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and, if corrected, could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also argued that off-system sales margins were allocated incorrectly. The intervenors reallocation of such margins would reduce PSOs recoverable fuel by $7 million for 2000 and $11 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $9 million. The intervenor and the OCC Staff also recommended recalculation of PSOs fuel costs for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. After reviewing the briefs, the ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. In January 2005, the OCC conducted a hearing on the jurisdictional matter and a ruling is expected in the near future. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

Virginia Fuel Factor Filing

On October 29, 2004, APCo filed a request with the Virginia State Corporation Commission (Virginia SCC) to increase its fuel factor effective January 1, 2005. The requested factor is estimated to increase revenues by approximately $19 million on an annual basis. This increase reflects a continuing rise in the projected cost of coal in 2005. By order dated November 16, 2004, the Virginia SCC approved APCos request on an interim basis, pending a hearingheld in February 2005. The Virginia SCC issued an order on February 11, 2005 approving the continuation of the January 1, 2005 interim fuel factor, which is subject to final audit. This fuel factor adjustment will increase cash flows without impacting results of operations as any over-recovery or under-recovery of fuel cost would be deferred as a regulatory liability or a regulatory asset.

Indiana Fuel Order

On August 27, 2003, the IURC ordered certain parties to negotiate the appropriate action on I&Ms fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment chargethat capped fuel recoveries (fixed pursuant to a prior settlement of Cook Nuclear Plant outage issues). I&M agreed, contingent on AEP implementing corporate separation for some of its subsidiaries, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although we have not corporately separated, certain parties believe the fixed fuel adjustment charge should continue beyond February 2004. Negotiations to resolve this issue are ongoing. The IURC ordered that the fixed fuel adjustment charge remain in place, on an interim basis, through April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor from May through September 2004, subject to true-up to actual fuel costs following the resolution of the issue regarding the corporate separation agreement. The IURC also reopened the corporate separation docket to investigate issues related to the corporate separation agreement. In July 2004, we filed for approval of a fuel factor for the period October 2004 through March 2005. On September 22, 2004, the IURC issued another order extending the interim fuel factor from October 2004 through March 2005, subject to true-up upon resolution of the corporate separation issues. At December 31, 2004, I&M has under-recovered its fuel costs by $2 million. If I&Ms net recovery should remain an under-recovery and if I&M would be required to continue to bill the existing fixed fuel adjustment factor that caps fuel revenues, future results of operations and cash flows would be adversely affected.

Michigan 2004 Fuel Recovery Plan

On September 30, 2003, I&M filed its 2004 Power Supply Cost Recovery (PSCR) Plan with the Michigan Public Service Commission (MPSC) requesting fuel and power supply recovery factors for 2004, which were implemented pursuant to statute effective with January 2004 billings. A public hearing was held on March 10, 2004. On June 4, 2004, the ALJ recommended that net SO_2 and NO_x credits be excluded from the fuel recovery mechanism. I&M filed its exceptions in June 2004. If the ALJs recommendation is adopted by the MPSC and in a future period SO_2 and NO_x are a net cost, it would adversely affect results of operations and cash flows. On September 30, 2004, I&M filed its 2005 PSCR Plan, which reflects net credits of approximately $5 million.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCCs proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%.

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCCs requested $67 million annual rate increase. Their recommendations ranged from a decrease in annual existing rates of approximately $100 million to an increase in TCCs current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a nonunanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCCs rate request from $67 million to $41 million.

On July 1, 2004, the ALJswho heard the case issued their recommendations which included a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded back to the ALJs for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling, the PUCT remanded six other issues to the ALJs requesting revisions to clarify and support the recommendations in the PFD.

The PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCCs calculations, the ALJs recommendations would reduce TCCs annual existing rates between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings.

On November 16, 2004, the ALJs issued their PFD on remand, increasing their recommended annual rate reduction to a range of $51 million to $78 million, depending on the amount disallowed related to affiliated AEPSC billed expenses. At the January 13, 2005 and January 27, 2005 open meetings, the Commissioners considered a number of issues, but deferred resolution of the affiliated AEPSC billed expenses issue, among other less significant issues, until after additional hearings scheduled for March 2005. Adjusted for the decisions announced by the Commissioners in January 2005, the ALJs' disallowance would yield an annual rate reduction of a range of $48 million to $75 million. If TCC were to prevail on the affiliated expenses issue and all remaining issues, the result would be an annual rate increase of $6 million. When issued, the PUCT orderwill affect revenues prospectively. An order reducing TCCs rates could have a material adverse effect on future results of operations and cash flows.

TCC and TNC ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the OPC and cities served by both TCC and TNC appealed the PUCTs December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court also ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCTs original decision will ultimately be upheld. If the District Courts decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in the years 2002 through 2004 resulting in an adverse effect on future results of operations and cash flows.

TCC Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCCs UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCCs excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCTs UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Courts decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

SWEPCo Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSCs merger order also provides that SWEPCos base rates are capped at the present level through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCos current rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in SWEPCos Louisiana jurisdictional base rates. SWEPCos rebuttal testimony was filed on January 16, 2005. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact future results of operations and cash flows.

PSO Rate Review

In February 2003, the OCC Staff filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC Staffs request. PSOs initial response indicated that its annual revenues were $36 million less than costs. The June 2004 filing updated PSOs request and indicated a $41 million revenue deficiency. As a result, PSO sought OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSOs existing revenues.

In August 2004, PSO filed a motion to amend the timeline to consider new service quality and reliability requirements, which took effect on July 1, 2004. Also in August 2004, the OCC approved a revised schedule. In October 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. In November 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO sought interim approval to collect annual incremental tree trimming costs of approximately $23 million from its customers. Intervenors and the OCC Staff filed testimony recommending that the interim rate relief requested by PSO be modified or denied. The OCC issued an order on PSOs interim request in January 2005, which allows PSO to recover up to an additional $12 million annually for reliability activities beginning in December 2004. Expenses exceeding that amount and the amount currently included in base rates will be considered in the base rate case.

The OCC Staff and intervenors filed testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in January 2005. Their recommendations ranged from a decrease in annual existing rates between $15 million and $36 million. In addition, one party recommended that the OCC require PSO file additional information regarding its natural gas purchasing practices. In the absence of such a filing, this party suggested that $30 million of PSOs natural gas costs not be recovered from customers because it failed to implement a procurement strategy that, according to this party, would have resulted in lower natural gas costs. OCC Staff and intervenors recommended a return on common equity ranging from 9.3% to 10.11%. PSOs rebuttal testimony was filed in February 2005, and that testimony reflects a number of adjustments to PSOs June 2004 updated filing. These adjustments result in a decrease of PSOs revenue deficiency in this case from $41 million to $28 million, although approximately $9 million of that decrease are items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

PSO Lawton Power Supply Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration Incorporated seeking avoided cost payments and approval of a power supply agreement, OCC issued an order approving payment of avoided costs and a Power Supply Agreement (Agreement). Among other things, in the order, the OCC did not approve PSOs recovery of the costs of the Agreement.

In December 2003, PSO filed an appeal of the OCCs order with the Oklahoma Supreme Court. In the appeal, PSO maintains that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. Should the OCCs order be upheld by the Supreme Court, PSO anticipates full recovery of the costs of the Agreement. However, if the OCC was to deny recovery of a material amount, it would adversely affect future results of operations and cash flows.

Upon resolution of this issue, management would review any transaction for the effect, if any, on the balance sheet relating to lease and FIN 46R accounting.

KPCo Environmental Surcharge Filing

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCos cost of compliance with the CAA.

RTO Formation/Integration

Based on FERC approvals in response to nonaffiliated companies requests to defer RTO formation costs, the AEP East companies deferred costs incurred under FERC orders to form a new RTO (the Alliance RTO) or subsequently to join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both Alliance RTO formation costs and PJM integration costs, including the deferral of a carrying charge thereon. The AEP East companies have deferred approximately $37 million of RTO formation and integration costs and related carrying charges through December 31, 2004.

In its July 2003 order, the FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the OATT to be charged by PJM. Management believes that the FERC will grant permission for prudently incurred deferred RTO formation/integration costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions treatment of the AEP East companies portion of the OATT as these companies file rate cases. As of December 31, 2004, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo and OPCo until January 1, 2006.

In August 2004, we filed an application with the FERC dividing the RTO formation/integration costs between PJM-incurred integration costs billed to us including related carrying charges, and all other RTO formation/integration costs. We intend to file with the FERC to request that deferred PJM-incurred integration costs billed to us be recovered from all PJM customers. We anticipate the other RTO formation/integration costs will be recovered through transmission rates in the AEP East zone. The AEP East companies will be responsible for paying most of the amount allocated by the FERC to the AEP East zone since it will be attributable to their internal load. In our August 2004 application, we requested permission to amortize over 15 years beginning January 1, 2005 the cost to be billed within the AEP East zone which represents approximately one-half of the total deferred RTO formation/integration costs. We also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, but we did not propose an amortization period in the application. The FERC has not ruled on our application.

The AEP East companies integrated into PJM on October 1, 2004. We intend to file a joint request with other new PJM members to recover approximately one-half of the deferred RTO formation/integration costs (i.e. the PJM-incurred integration expenses billed to AEP) through a new charge in the PJM OATT that would apply to all loads and generation in the PJM region during a 10-year period beginning in May 2005. The AEP East companies will expense their portion of the PJM-incurred integration costs billed by PJM under the new charge. We will amortize the remaining portion of our RTO formation/integration costs over the period to be approved by the FERC and seek recovery of such costs in the retail rates for each of the AEP East companies state jurisdictions. Management believes that it is probable that the FERC will approve recovery of the PJM-incurred integration costs to be billed to us through the PJM OATT and that the FERC will grant a long enough amortization period to allow for the opportunity for recovery of the non-PJM incurred RTO formation/integration costs in the AEP East retail jurisdictions. If the FERC ultimately decides not to approve an amortization period that would provide us with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of our share of these deferred costs, future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC is expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that we previously recovered from our T&O service customers to mainly AEPs native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP and Exelon filed joint comments and protests with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an orderindicating that the SECA transition rates would be subject to refund or surcharge andset for hearing all remaining aspects of the compliance filings to the November 18 order, including the our request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues within the PJM/MISO Expanded Footprint for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEPs internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or if any increase in the AEP East companies transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding

In its July 2002 order conditionally accepting our choice to join PJM, the FERC directed us, ComEd, MISO and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO. In December 2003, AEP and ComEd jointly filed a hold-harmless proposal, which was rejected by the FERC in March 2004 without prejudice to the filing of a new proposal.

In July 2004, AEP and PJM filed jointly with the FERC a new hold-harmless proposal that was nearly identical to a proposal filed jointly by ComEd and PJM in April 2004. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for April 2005.

The proposed hold-harmless agreement as filed by PJM and us specifies that the term of the agreement commences on October 1, 2004 and terminates when the FERC determines that effective internalization of congestion and loop flows is accomplished. The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 to $70 million over the term of the agreement for ComEd and AEP. The recent supplemental filing by the Michigan companies show estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 which is pending approval before the FERC.

At this time, management is unable to predict the outcome of this proceeding. AEP will support vigorously its positions before the FERC. No provision has been established. If the FERC ultimately approves a significant hold-harmless payment to the Michigan and Wisconsin utilities, it would adversely impact results of operations and cash flows.

FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a pivotal supplier test which determines if the market load can be fully served by alternative suppliers and a market share test which compares the amount of surplus generation at the time of the applicants minimum load. In July 2004, the FERC issued an order on rehearing, affirming its conclusions in the April order and directing AEP and two nonaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERCs current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, as amended on September 16, 2004 and November 19, 2004, AEP submitted its generation market power screens in compliance with the FERCs orders. The analysis focused on the three major areas in which AEP serves load and owns generation resources -- ECAR, SPP and ERCOT, and the first tier control areas for each of those areas.

The pivotal supplier and market share screen analyses that AEP filed demonstrated that AEP does not possess market power in any of the control areas to which it is directly connected (first-tier markets). AEP passed both screening tests in all of its first tier markets. In its three home control areas, AEP passed the pivotal supplier test. AEP, as part of PJM, also passes the market share screen for the PJM destination market. AEP also passed the market share screen for ERCOT. AEP did not pass the market share screen as designed by the FERC for the SPP control area.

In a December 17, 2004 order, FERC affirmed our conclusions that we passed both market power screen tests in all areas except SPP. Because AEP did not pass the market share screen in SPP, FERC initiated proceedings under Section 206 of the Federal Power Act in which AEP is rebuttably presumed to possess market power in SPP. Consequently, our revenues from sales in SPP at market based rates after March 6, 2005 will be collected subject to refund to the extent that prices are ultimately found not to be just and reasonable. On February 15, 2005, although we continue to believe we do not possess market power in SPP, we filed a response and proposed tariff changes to address FERCs market-power concerns. The proposed tariff change would apply to sales that sink within the service territories of PSO, SWEPCo and TNC within the SPP that encompass the AEP-SPP control area, and make such sales subject to cost-based rate caps. We have requested the amended tariffs to become effective March 6, 2005.

In addition to FERC market monitoring, we are subject to market monitoring oversight by the RTOs in which we are a member, including PJM and SPP. These market monitors have authority for oversight and market power mitigation.

Management believes that we are unable to exercise market power in any region. At this time the impact on future wholesale power revenues, results of operations and cash flows of the FERCs and PJMs market power analysis cannot be determined.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31,		Future Recovery/Refund Period
	2004	**2003**	
	(in millions)		
Regulatory Assets:			
Income Tax Related Regulatory Assets, Net	$ 796	$ 728	Various Periods (a)
Transition Regulatory Assets	407	529	Up to 6 Years (a)
Designated for Securitization	1,361	1,289	(b)
Texas Wholesale Capacity Auction True-up	560	480	(c)
Unamortized Loss on Reacquired Debt	116	116	Up to 39 Years (d)
Cook Nuclear Plant Refueling Outage Levelization	44	57	(e)
Other	317	383	Various Periods (f)
Total Regulatory Assets	$ 3,601	$ 3,582	
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	$ 1,290	$ 1,233	(g)
Deferred Investment Tax Credits	393	422	Up to 25 Years (a)
Excess ARO for Nuclear Decommissioning Liability	245	216	(h)
Over-recovery of Texas Fuel Costs	216	150	(c)
Deferred Over-recovered Fuel Costs	71	63	(a)
Texas Retail Clawback	75	57	(c)
Other	250	254	Various Periods (f)
Total Regulatory Liabilities	$ 2,540	$ 2,395	

(a) Amount does not earn a return.

(b) Amount includes a carrying cost, will be included in TCCs True-up Proceeding and is designated for possible securitization. The cost of the securitization bonds would be recovered over a time period to be determined in a future PUCT proceeding.

(c) See Texas Restructuring and Carrying Costs on Net-True-up Regulatory Assets sections of Note 6 for discussion of carrying costs. Amounts will be included in TCCs and TNCs true-up proceedings for future recovery/refund over a time period to be determined in a future PUCT proceeding.

(d) Amount effectively earns a return.

(e) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.

(f) Includes items both earning and not earning a return.

(g) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

(h) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, accrues monthly, and will be paid when the nuclear plant is decommissioned.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory Assets Designated for Securitization, Texas Wholesale Capacity Auction True-up regulatory assets, Over-recovery of Fuel Costs and Texas Retail Clawback regulatory liabilities are not currently being recovered from or returned to ratepayers. Management believes that the laws and regulations established in Texas for industry restructuring provide for the recovery from ratepayers of these net amounts. These amounts require approval of the PUCT in a future True-up Proceeding. See Note 6 for a complete discussion of our plans to seek recovery of these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage restart costs were approved in 1999 by the Indiana Utility Regulatory Commission and Michigan Public Service Commission.

The amount of deferrals amortized to maintenance and other operation expenses under the settlement agreements were $40 million in both 2003 and 2002. The Nuclear Plant Restart regulatory asset was fully amortized as of December 31, 2004 and 2003. Also, pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 were amortized as a reduction of revenues. The amortization of amounts deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements:

Summary of key provisions of Merger Rate Agreements:

State/Company	**Ratemaking Provisions**
Texas - SWEPCo, TCC, TNC	Rate reductions of $221 millionover 6 years.
Indiana - I&M	Rate reductions of $67 millionover 8 years.
Michigan - I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky - KPCo	Rate reductions of approximately $28 million over 8 years.
Oklahoma - PSO	Rate reductions of approximately $28 million over 5 years.
Arkansas - SWEPCo	Rate reductions of $6 million over 5 years.
Louisiana - SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years and a base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Merger Litigation section of Note 7 for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of our eleven electric utility companies (CSPCo, I&M, APCo, OPCo, TCC and TNC) are in various stages of transitioning to customer choice and/or market pricing for the supply of electricity in four of the eleven state retail jurisdictions (Ohio, Texas, Michigan and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events related to industry restructuring in those states.

OHIO RESTRUCTURING

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The Public Utilities Commission of Ohio (PUCO) may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utilitys certified territory or that there is a twenty percent switching rate of the incumbent utilitys load by customer class. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rules provide for a Market Based Standard Service Offer (MBSSO) which would be a variable rate based on transparent forward market, daily market, and/or hourly market prices. The rules also require a fixed-rate Competitive Bidding Process (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the MBSSO and the CBP. Customers who make no choice will be served pursuant to the CBP. The rules also required that electric distribution utilities file an application for MBSSO and CBP by July 1, 2004. CSPCo and OPCo were granted a waiver from making the required MBSSO/CBP filing, pending the outcome of a rate stabilization plan they filed with the PUCO in February 2004. As of December 31, 2004, none of OPCos customers have elected to choose an alternate power supplier and only a modest number of CSPCos small commercial customers has switched suppliers. This is believed to be due to CSPCos and OPCos rates being below market.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEPs generation resources that serve Ohio customers. On January 26, 2005, the PUCO approved the plans with some modifications.

The approved plans include annual fixed increases in the generation component of all customers bills (3% a year for CSPCo and 7% a year for OPCo) in 2006, 2007 and 2008. The plan also includes the opportunity to annually request an additional increase in supply prices averaging up to 4% per year for each company to recover certain new governmentally-mandated increased expenditures set out in the approved plan. The plans maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level in effect on December 31, 2005. Such rates could be adjusted with PUCO approval for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion and ancillary services. The approved plans provide for the continued amortization and recovery of stranded transition generation-related regulatory assets. The plans, as modified by the PUCO, require CSPCo and OPCo to allot a combined total of $14 million of previously provided for unspent shopping incentives for the benefit of their low-income customers and economic development over the three-year period ending December 31, 2008 which will not have an effect on net income. The plan also authorized each company to establish unavoidable riders applicable to all distribution customers in order to be compensated in 2006 through 2008 for certain new costs incurred in 2004 and 2005 of fulfilling the companies Provider of Last Resort (POLR) obligations. These costs include RTO administrative fees and congestion costs net of financial transmission revenues and carrying cost of environmental capital expenditures. As a result, in 2005, CSPCo and OPCoexpect to record regulatory assets of $8 millionand $21 million, respectively, forthe subject costsrelated to2004 and $14 million and $52 million, respectively, for expected subject costs related to 2005. These regulatory assets, totaling $22 million for CSPCo and $73 million for OPCowill be amortized as the costs are recovered through POLR riders in 2006 through 2008. The riders, together with the fixed annual increases in generation rates are estimated to provide additional cumulative revenues to CSPCo and OPCo of $190 million and $500 million, respectively, in the three-year period ended December 31, 2008. Other revenue increases may occur related to other provisions of the plan discussed above.

On February 25, 2005, various intervenors filed Applications for Rehearing with the PUCO regarding their approval of the rate stabilization plans. Management expects the PUCO to address the applications before the end of March 2005. Management cannot predict the ultimate impact these proceedings will have on the results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through December 31, 2004, we incurred $78 million of such costs, and accordingly, we deferred $38 million such costs for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the rate stabilization plan, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. Management believes that the deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNCs business is in SPP.

The Texas Restructuring Legislation, among other things:

- provides for the recovery of net stranded generation costs and other generation true-up amounts through securitization and nonbypassable wires charges,
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
- provides for an earnings test for each of the years 1999 through 2001 and,
- provides for a stranded cost True-up Proceeding after January 10, 2004.

The Texas Restructuring Legislation also required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold two of its affiliated price-to-beat REPs serving ERCOT customers to a nonaffiliated company.

TEXAS TRUE-UP PROCEEDINGS

The True-up Proceedings will determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCTs excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
- final approved deferred fuel balance, and
- net carrying costs on true-up amounts.

The PUCT adopted a rule in 2003 regarding the timing of the True-up Proceedings scheduling TCCs filing 60 days after the completion of the sale of TCCs generation assets. Due to regulatory and contractual delays in the sale of its generating assets, TCC has not yet filed its true-up request. TNC filed its true-up request in June 2004 and updated the filing in October 2004. Since TNC is not a stranded cost company under Texas Restructuring Legislation, the majority of the true-up items in the table below do not apply to TNC.

Net True-up Regulatory Asset (Liability) Recorded at December 31, 2004:

	TCC	TNC
	(in millions)	
Stranded Generation Plant Costs	$ 897	$ -
Net Generation-related Regulatory Asset	249	-
Unrefunded Excess Earnings	(10)	-
Net Stranded Generation Costs	1,136	-
Carrying Costs on Stranded Generation Plant Costs	225	-
Net Stranded Generation Costs Designated for Securitization	1,361	-
Wholesale Capacity Auction True-up	483	-
Carrying Costs on Wholesale Capacity Auction True-up	77	-
Retail Clawback	(61)	(14)
Deferred Over-recovered Fuel Balance	(212)	(4)
Net Other Recoverable True-up Amounts	287	(18)
Total Recorded Net True-up Regulatory Asset (Liability)	$ 1,648	$ (18)

Amounts listed above include fourth quarter 2004 adjustments made to reflect the applicable portion of the PUCTs decisions in prior nonaffiliated utilities True-up Proceedings discussed below.

Net Stranded Generation Costs

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC is the only AEP subsidiary that has stranded generation plant costs under the Texas Restructuring Legislation. TCC elected to use the sale of assets method to determine the market value of its generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCCs generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCCs generation capacity in Texas. We received bids for all of TCCs generation plants. In January 2004, TCC agreed to sell its 7.81% ownership interest in the Oklaunion Power Station to a nonaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% ownership interest in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to nonaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion, STP and the coal, gas and hydro plants. TCC received a notice from co-owners of Oklaunion and STP exercising their rights of first refusal; therefore, SEC approval will be required. The original nonaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and the co-owners rights of first refusal void. The sale of STP will also require approval from the Nuclear Regulatory Commission. On July 1, 2004, TCC completed the sale of its other coal, gas and hydro plants for approximately $428 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. In December 2003, based on an expected loss from the sale of its generating assets, TCC recognized as a regulatory asset an estimated impairment from the sale of TCCs generation assets of approximately $938 million. The impairment was computed based on an estimate of TCCs generation assets sales price compared to book basis at December 31, 2003. On February 15, 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets. TCC asked the PUCT to rule on the request in April 2005.

On December 17, 2004, the PUCT issued an Order on Rehearing in the CenterPoint True-Up Proceeding (CenterPoint Order). All motions for rehearing of that order were denied on January 18, 2005, and the PUCTs decision is now final and appealable. Among other things, the CenterPoint Order provided certain adjustments to stranded generation plant costs to avoid what the PUCT deemed to be duplicative recovery of stranded costs and the capacity auction true-up amount, as further discussed below (See Wholesale Capacity Auction True-up below). The CenterPoint Order also confirmed that stranded costs are to be determined as of December 31, 2001, and, as also discussed below, the CenterPoint Order identified how carrying costs from that date are to be computed (see Carrying Costs on Net True-Up Regulatory Assets below).

In the fourth quarter of 2004, TCC made adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis (instead of December 31, 2003 book basis), including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCCs stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in the CenterPoint Order discussed below under Wholesale Capacity Auction True-up. These adjustments are reflected as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in our Consolidated Statements of Operations. Management believes that with these adjustments to TCCs stranded generation plant costs regulatory asset, it has complied with the portions of the PUCTs to-date orders in other Texas companies true-up proceedings that apply to TCC.

In addition to the two items discussed above (the $938 million impairment in 2003 and the $185 million adjustment in 2004), TCC had recorded $121 million of impairments in 2002 and 2003 on its gas-fired plants. Additionally, other miscellaneous items and the costs to complete the sales, which are still ongoing, of $23 million are included in the recoverable stranded generation plant costs of $897 million.

The Texas Restructuring Legislation permits TCC to recover as its net stranded generation costs $897 million of stranded generation plant cost plus its remaining not yet securitized net generation-related transition regulatory asset of $249 million less a regulatory liability for the unrefunded excess earnings of $10 million, discussed below. With the above net extraordinary basis adjustments from applicable portions of the PUCTs prior nonaffiliated true-up orders, TCCsnet stranded generation costs before carrying costs totaled $1.1 billion at December 31, 2004.

In the CenterPoint Order, the PUCT decided that net stranded generation costs should be reduced by the present value of deferred investment tax credits (ITC) and excess deferred federal income taxes applicable to generating assets. CenterPoint testified in its true-up proceeding that acceleration of the sharing of deferred ITC with customers may be a violation of the Internal Revenue Codes normalization provisions. Management agrees with CenterPoint that the PUCTs acceleration of deferred ITC and excess deferred federal income taxes may be a violation of the normalization provisions. As a result, management does not intend to include as a reduction of its net stranded generation costs the present value of TCCs generation-related deferred ITC of $70 million and the present value of excess deferred federal income taxes of $6 million in its future true-up filing. As a result, such amounts are not reflected as a reduction of TCCs net stranded generation costs in the above table. The Internal Revenue Service (IRS) has issued proposed regulations that would make an exception to the normalization provisions for a utility whose electric generation assets cease to be public utility property. If the IRS does not issue final regulations with protective provisions prior to the filing of TCCs true-up, management intends to seek a private letter ruling from the IRS to determine whether the PUCTs action would result in a normalization violation. A normalization violation could result in the repayment of TCCs accumulated deferred ITC on all property, not just generation property, which approximates $108 million as of December 31, 2004, and a loss of the ability to elect accelerated tax depreciation in the future. Management is unable to predict how the IRS will rule on a private letter ruling request and whether TCC will ultimately suffer any adverse effects on its future results of operations and cash flows.

Unrefunded Excess Earnings

The Texas Restructuring Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. TCC, TNC and SWEPCo challenged the PUCTs treatment of fuel-related deferred income taxes in the computation of excess earnings and appealed the PUCTs final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. However, upon further appeal of the District Court ruling upholding the PUCT decision, the Third Court of Appeals reversed the PUCT order and the District Courts judgment. The District Court remanded to the PUCT an appeal of the same issue from the PUCTs 2001 order upon agreement of the parties after issuance of the Third Court of Appeals decision. On September 14, 2004, the parties to the PUCT remand reached an agreement, which changed the method for calculating excess earnings which, in turn, revised the calculation for 2000 and 2001 consistent with the ruling of the court. The PUCT issued a final order approving the agreement in October 2004. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, all three companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Courts decision and credited amortization expense during the third quarter of 2003. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant costs, excess earnings have been applied to reduce T&D capital expenditures and are not a true-up item.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduces cash flows over the refund period. The remaining $10 million to be refunded is recorded as a regulatory liability at December 31, 2004 and will be included as a reduction to TCCs net stranded generation costs unless it has been fully refunded. Management believes that TCC has stranded generation plant costs and that it is, therefore, inconsistent with the Texas Restructuring Legislation for the PUCT to have ordered a refund prior to TCCs True-up Proceeding. TCC appealed the PUCTs premature refund of excess earnings to the Travis County District Court. That court affirmed the PUCTs decision and further ordered that the refunds be provided to ultimate customers. TCC has appealed the decision to the Third Court of Appeals.

In January 2005, intervenors filed testimony in TNCs True-up Proceeding recommending that TNCs excess earnings be increased by approximately $5 million to reflect carrying charges on its excess earnings for the period from January 1, 2002 to March 2005. A decision from the PUCT will likely be received in the second quarter of 2005.

Wholesale Capacity Auction True-up

The Texas Restructuring Legislation required that electric utilities and their affiliated power generation companies (PGCs) offer for sale at auction, in 2002, 2003 and thereafter, at least 15% of the PGCs Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. According to the legislation, the actual market power prices received in the state-mandated auctions are used to calculate wholesale capacity auction true-up revenues for recovery in the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. Based on its auction prices, TCC recorded a regulatory asset and related revenues of $262 million in 2002 and $218 million in 2003 which represented the quantifiable amount of the wholesale capacity auction true-up. The cumulative amount before carrying costs was adjusted to $483 million in the fourth quarter of 2004. TCC also recorded $77 million of carrying costs in the fourth quarter of 2004 related to the wholesale capacity auction true-up, increasing the total asset to $560 million.

In the CenterPoint Order, the PUCT made three significant adverse adjustments to CenterPoints and its affiliated PGCs request for recovery related to its capacity auction true-up regulatory asset. First, the PUCT determined that CenterPoint had not met what the PUCT interpreted as a requirement to sell 15% of its generation capacity at the state-mandated auctions. Accordingly, an adjustment was made to reflect prices obtained in other auctions of CenterPoints affiliated PGCs generation. Parties to the TCC proceeding may also contend that TCC has not met the requirement to auction 15% of its generation capacity. However, based on facts not applicable to the CenterPoint case, TCC will contend that it has met the requirement. Even if it were determined that TCC has not complied with the requirement, facts unique to TCC might mitigate the potential impact and make the method of calculating an impact uncertain. Since the facts in the CenterPoint decision differ from TCCs facts and circumstances, TCC has not recorded any provisions to reflect a similar adverse adjustment to its net true-up regulatory asset.

Second, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002-2003. The PUCT then determined that depreciation is a component of that recovery and, because depreciation represents a return of investment in generation assets, it disallowed 2002 and 2003 depreciation as a duplicative recovery of stranded costs. In the CenterPoint Order, the PUCT determined that there was a duplication of depreciation due to the fact that the stranded generation plant costs also include amounts depreciated in 2002 and 2003 because the stranded generation plant costs were determined as of December 31, 2001. TCC disagrees that the purpose of the capacity auction true-up is to provide a traditional regulated recovery during 2002 through 2003. Moreover, TCC will contend, among other things, that the PUCTs method of calculating the capacity auction true-up did not permit TCC to fully recover 2002 through 2003 depreciation expense. Nonetheless, based on the determination made by the PUCT in the CenterPoint case and the probability that it will interpret the law in the same manner in TCCs case, TCC recorded a $238 million reduction to its stranded generation plant costs in December 2004 which is reflected as a component of the Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in our Consolidated Statements of Operations.

Third, the PUCT determined in the CenterPoint case that any nonfuel revenues produced by the capacity auction true-up regulatory asset which exceed nonfuel revenues for 2002-2003 from traditional regulation is a margin or return which is duplicative of the carrying cost. As noted above, TCC intends to challenge the conclusion that the capacity auction true-up was intended to provide a traditional regulated recovery. In addition, TCC will contend, that when applied to TCC, the calculation adopted for CenterPoint in which the PUCT determined that CenterPoint had duplicative return of carrying costs actually produces a $206 million negative margin. It will be TCCs position that it should have the right to recover the negative margin if the purpose of the capacity auction is to allow a traditional regulated recovery. As a result, TCC has recorded no adjustment to reflect this determination in the CenterPoint case.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is referred to as the the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In December 2003, the PUCT certified that the REPs in the TCC and TNC service territories had reached the 40% threshold for the small commercial class. As a result, TCC and TNC reversed $6 million and $3 million, respectively, of retail clawback regulatory liabilities previously accrued for the small commercial class. Based upon customer information filed by the nonaffiliated company, which operates as the PTB REP for TCC and TNC, TCC and TNC updated their estimated residential retail clawback regulatory liability. At December 31, 2004, TCCs recorded retail clawback regulatory liability was $61 million and TNCs was $14 million. TCC and TNC each recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $32 million and $7 million, respectively, for their share of the retail clawback liability.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. In October 2004, the PUCT issued a final order which resulted in an over-recovery balance of $4 million. TNC had adjusted its deferred fuel balance in 2003 by $20 million and in 2004 by $10 million in compliance with the final PUCT order. Challenges to that order were filed in December 2004 in federal and state district courts.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery fuel balance for inclusion in the True-up Proceeding. TCC provided for disallowances increasing its regulatory fuel over-recovery liability by $81 million in 2003 and $62 million in 2004. On February 24, 2005,the PUCT in its open meeting increased the over-recovery byapproximately $2 million, inclusive of interest, for imputed capacity. TCC has provided for a $212 million deferred over-recovery fuel balance at December 31, 2004, which does not include the $2 million disallowance ruled by the PUCT. However, management is unable to predict the amount, if any, of any additional disallowances of TCCs final fuel over-recovery balance which will be included in its True-up Proceeding until a final order is issued. Management believes it has materially provided for probable to date disallowances in TCCs final fuel proceeding pending receipt of an order.

See TCC Fuel Reconciliation and TNC Fuel Reconciliations in Note 4 for further discussion.

Carrying Costs on Net True-up Regulatory Assets

In December 2001, the PUCT issued a rule concerning stranded cost true-up proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the utilities, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and ordered that the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling became final.

In the CenterPoint Order, the PUCT addressed the Supreme Courts remand decision and specified the manner in which carrying costs should be calculated. In December 2004, TCC computed, based on its interpretation of the methodology contained in the CenterPoint Order, carrying costs of $470 million for the period January 1, 2002 through December 31, 2004 on its stranded generation plant costs net of excess earnings and its wholesale capacity auction true-up regulatory assets at the 11.79% overall pretax cost of capital rate in its UCOS rate proceeding. The embedded 8.12% debt component of the carrying cost of $302 million ($225 million on stranded generation plant costs and $77 million on wholesale capacity auction true-up) was recognized in income in December 2004. This amount is included inCarrying Costs on Texas Stranded Cost Recoveryin our Consolidated Statements of Operations. Of the $302 million recorded in 2004, approximately $109 million, $105 million and $88 million related to the years 2004, 2003 and 2002, respectively. The remaining equity component of $168 million will be recognized in income as collected.

TCC will continue to accrue a carrying cost at the rate set forth above until it recovers its approved net true-up regulatory asset. The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until one year after a final order is issued in the fuel proceeding or a final order is issued in TCCs True-up Proceeding, whichever comes first. At that time, a carrying cost will begin to accrue on the deferred fuel. For all remaining true-up items, including the retail clawback, a carrying cost will begin to accrue when a final order is issued in TCCs True-up Proceeding. If the PUCT further adjusts TCCs net true-up regulatory asset in TCCs True-up Proceeding, the carrying cost will also be adjusted.

Stranded Cost Recovery

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through nonbypassable transition charges and competition transition charges in the regulated T&D rates. TCC will seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of the resultant securitization bonds will be recovered through a nonbypassable transition charge collected by the T&D utility over the term of the securitization bonds. The other approved net true-up items will be recovered or refunded over time through a nonbypassable competition transition wires charge or credit inclusive of a carrying cost.

TCCs recorded net true-up regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.6 billion at December 31, 2004. The securitizable portion of this net true-up regulatory asset, which consists of net stranded generation costs plus related carrying costs, was $1.4 billion at December 31, 2004. We expect that TCCs True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net true-up regulatory asset through December 31, 2004. The PUCT will review TCCs filing and determine the amount for the recoverable net true-up regulatory assets.

Due to differences between CenterPoints and TCCs facts and circumstances, the lack of direct applicability of certain portions of the CenterPoint Order to TCC and the unknown nature of future developments in TCCs True-up Proceeding, we cannot, at this time, determine if TCC will incur disallowances in its True-up Proceeding in excess of the $185 million provided in December 2004. We believe that our recorded net true-up regulatory asset at December 31, 2004 is in compliance with the Texas Restructuring Legislation, and the applicable portions of the CenterPoint Order and other nonaffiliated true-up orders, and we intend to seek vigorously its recovery. If, however, we determine that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from managements interpretation of the Texas Restructuring Legislation and its evaluation of the applicable portions of the CenterPoint and other true-up orders, additional material disallowances are possible.

TNC 2004 True-up Filing

In June 2004, TNC filed its True-up Proceeding which included the fuel reconciliation balance and the retail clawback calculation. The amount of the deferred over-recovered fuel balance at December 31, 2004 was approximately $4 million. TNC filed an update to its true-up filing to reflect the final order in its fuel reconciliation proceeding. The retail clawback regulatory liability included in the filing was adjusted in 2004 to $14 million, reflecting the number of customers served on January 1, 2004. In January 2005, intervenors filed testimony recommending that TNCs over-recovery be increased by up to approximately $2 million. In addition, they recommended that TNCs excess earnings be increased by approximately $5 million for carrying charges and its T&D rates be reduced by a maximum amount of approximately $3 million on an annual basis to reflect the return on excess earnings approved by the PUCT for the period 1999 through 2001. TNC does not agree with the intervenors reconciliation and filed rebuttal testimony. Management believes it has materially provided for all probable to date disallowances in TNCs True-up Proceeding.

MICHIGAN RESTRUCTURING

Customer choice commenced for I&Ms Michigan customers on January 1, 2002. Effective with that date, the rates on I&Ms Michigan customers bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&Ms total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2004, none of I&Ms customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&Ms Michigan service territory. As a result, management has concluded that as of December 31, 2004 the requirements to apply SFAS 71 continue to be met since I&Ms rates for generation in Michigan continue to be cost-based regulated.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation that extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

ARKANSAS RESTRUCTURING

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCos Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition.

WEST VIRGINIA RESTRUCTURING

In 2000, the Public Service Commission of West Virginia (WVPSC) issued an order approving an electricity- restructuring plan, which the West Virginia Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the West Virginia legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the West Virginia Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the West Virginia Legislature again failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCos outside counsel advised us that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSCs jurisdiction and rate authority over APCos West Virginia generation. As a result, in March 2003, management concluded that deregulation of APCos West Virginia generation business was no longer probable and operations in West Virginia met the requirements to reapply SFAS 71. Reapplying SFAS 71 in West Virginia had an insignificant effect on 2003 results of operations and financial condition.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to perfect its complaint in the pending litigation. The NOV expands the number of alleged modifications undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, eight Northeastern States filed a separate complaint containing the same allegations against the Conesville and Amos plants that the judge disallowed in the pending case. AEP filed an answer to the complaint in January 2005, denying the allegations and stating its defenses.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not routine maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial was scheduled for July 2004, but has been postponed to facilitate further settlement discussions.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, a nonaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is routine maintenance, repair, or replacement and on whether or not a significant net emissions increase results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is routine within the relevant source category in determining if it is routine. Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals. The District Court denied the Federal EPAs motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that eliminated the need for a trial, but preserving plaintiffs right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals. The case is fully briefed and oral argument was heard on February 3, 2005.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged CAA violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and in May 2004, that petition was denied.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 CAA rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case. Briefing continues in this case and oral argument was held in January 2005.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines routine maintenance repair and replacement to include functionally equivalent equipment replacement. Under the new rule, replacement of a component within an integrated industrial operation (defined as a process unit) with a new component that is identical or functionally equivalent will be deemed to be a routine replacement if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and was to become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003, twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

In December 2000, Cinergy Corp., a nonaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the CAA. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergys settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlements impact on its jointly-owned facilities and its future results of operations and cash flows.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. On September 21, 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the Stuart Station, and seeking injunctive relief and civil penalties. The owners have filed a motion to dismiss portions of the complaint. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant, but after investigation determined further enforcement action was not warranted and withdrew the notice on January 5, 2005.

SWEPCo has previously reported to the TCEQ deviations related to the receipt of off-specification fuel at Knox Lee, the volatile organic compound emissions at Pirkey, and the referenced recordkeeping and reporting requirements and heat input value at Welsh. We have submitted additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

NUCLEAR

Nuclear Plants

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement, I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurers financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2005 with increases in required third party financial protection for nuclear incidents.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $229 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2004, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low-level radioactive waste accumulation disposal costs for Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2004, 2003 and 2002.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. In May 2004, an updated decommissioning study was completed for STP. The study estimates TCCs share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year.

As discussed in Note 10, TCC is in the process of selling its ownership interest in STP to two nonaffiliates, and upon completion of the sale, it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2004 and $12 million in both 2003 and 2002 related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for the Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCCs nuclear decommissioning trust asset and liability are included in held for sale amounts on the Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2005 for consolidated operations are estimated to be $2.7 billion including amounts for proposed environmental rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Our subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

The AEP System has a unit contingent contract to supply approximately 250 MW of capacity to a nonaffiliated entity through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated qualifying cogeneration facility for purposes of PURPA. Commercial operation of the Facility as required by the agreements between Juniper, AEP and Dow was achieved on March 18, 2004. The initial term of our lease with Juniper (Juniper Lease) commenced on March 18, 2004 and terminates on June 17, 2009. We may extend the term of the Juniper Lease to a total lease term of 30 years. Our lease of the Facility is reported as an owned asset under a lease financing transaction. Therefore, the asset and related liability for the debt and equity of the facility are recorded on our Consolidated Balance Sheets and the obligations under the lease agreement are excluded from the table of future minimum lease payment in Note 16.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing of up to $494 million and equity of up to $31 million from investors with no relationship to AEP or any of AEPs subsidiaries.

The Facility is collateral for Junipers debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Junipers funded obligations as a liability of $520 million. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper Lease, our maximum cash payment could be as much as $525 million.

We have the right to purchase the Facility for the acquisition cost during the last month of the Juniper Leases initial term or on any monthly rent payment date during any extended term of the lease. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to a nonaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dows rights to lease the Facility or our contract to purchase energy from Dow as described below. If the lease is renewed for up to a 30-year lease term, then at the end of that 30-year term we may further renew the lease at fair market value subject to Junipers approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Junipers acquisition costs, we may be required to make a payment (not to exceed $415 million) to Juniper for the excess of Junipers acquisition cost over the proceeds from the sale. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report Junipers funded obligations related to the Facility on our Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

At December 31, 2004, Junipers acquisition costs for the Facility totaled $520 million, and the total acquisition cost for the completed Facility is currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR (plus a component for a fixed-rate return on Junipers equity investment and an administrative charge). Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $23 million represent future minimum lease payments to Juniper during the initial term. The majority of the payment is calculated using the indexed LIBOR rate (2.55% at December 31, 2004). Annual sublease payments received from Dow are approximately $27 million (substantially based on an adjusted three-month LIBOR rate discussed above).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000, (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purpose of the PPA began April 2, 2004.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEPs breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the creation of protocols was not subject to arbitration, but did not rule upon the merits of TEMs claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is in the discovery phase, with trial scheduled to begin in March

2005.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the Commercial Operations Date. Despite OPCos prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCos tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

See Power Generation Facility section of Note 10 for further discussion.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be physically interconnected and confined to a single area or region. In January 2005, a hearing was held before an ALJ. We expect an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enrons bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enrons bankruptcy.

Enron Bankruptcy - Bammel storage facility and HPL indemnification matters - In connection with the 2001 acquisition of HPL, we entered into a prepaid arrangement under which we acquired exclusive rights to use and operate the underground Bammel gas storage facility and appurtenant pipeline pursuant to an agreement with BAM Lease Company. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years.

In January 2004, we filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron did not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In April 2004, AEP and Enron entered into a settlement agreement under which we acquired title to the Bammel gas storage facility and related pipeline and compressor assets, plus 10.5 billion cubic feet (BCF) of natural gas currently used as cushion gas for $115 million, which increased our investment in HPL. AEP and Enron agreed to release each other from all claims associated with the Bammel facility, including our indemnity claims. The settlement received Bankruptcy Court approval in September 2004 and closed in November 2004. The parties respective trading claims and Bank of Americas (BOA) purported lien on approximately 55 BCF of natural gas in the Bammel storage reservoir (as described below) are not covered by the settlement agreement.

Enron Bankruptcy - Right to use of cushion gas agreements - In connection with the 2001 acquisition of HPL, we also entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 BCF of cushion gas (including the 10.5 BCF described in the preceding paragraph) required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in state court in Texas seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOAs claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enrons financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOAs Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA has objected to the Magistrate Judges decision and the matter is now before the District Judge.

In February 2004, in connection with BOAs dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enrons attempted rejection of these agreements.

On January 26, 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of our 98% interest in HPL against any damages resulting from the BOA litigation. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute (see Note 19).

Enron Bankruptcy - Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEPs offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding, court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enrons claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claim in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

Enron Bankruptcy - Summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and managements analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that we failed to disclose that alleged round trip trades resulted in an overstatement of revenues, that we failed to disclose that our traders falsely reported energy prices to trade publications that published gas price indices and that we failed to disclose that we did not have in place sufficient management controls to prevent round trip trades or false reporting of energy prices. The plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In September 2004, the U.S. District Court Judge dismissed the cases and expressly denied the plaintiffs request for an opportunity to file amended complaints with new and revised allegations. The plaintiffs did not appeal this decision.

In the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over our gas trading operations. In November 2004, these cases were dismissed. Also, in the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEPs Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions are pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. We have filed a Motion to Dismiss these actions, which the Court denied. We have filed a Motion for Leave to file an interlocutory appeal seeking review of part of the Courts decision. The cases are in the discovery stage. We intend to continue to defend vigorously against these claims.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Management is unable to predict the outcome of these lawsuits but intends to defend vigorously against the claims made in each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint, which the Court denied in September 2004. We intend to defend vigorously against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against certain nonaffiliated energy companies, ERCOT, four AEP subsidiaries and us. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial courts decision to the United States Court of Appeals for the Fifth Circuit.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with usand claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million related to previously recorded receivables on which we hold approximately $20 million of credit collateral. We have reserved $4 million against these receivables to reflect the risks of loss, based on the low end of a range of valuations calculated for purposes of the litigation and related mediation. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Coal Transportation Dispute

Certain of our subsidiaries, as joint owners of a generating station have disputed transportation costs billed for coal received between July 2000 and the present time. Our subsidiaries have remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, our subsidiaries recorded a provision for possible loss in December 2004. Of the total provision, a share for deregulated subsidiaries affected income in 2004, a share was recorded as a receivable due to partial ownership of the plant by third parties and the remainder was deferred under the operation of a deferred fuel mechanism. Management continues to work toward mitigating the disputed amounts to the extent possible.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by certain wholesale customers located in Nevada. The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were high-priced. The complaint alleged that we sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities had filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJs decision. The utilities request for a rehearing was denied. The utilities appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

Energy Market Investigation

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and continued to respond to supplemental data requests from some of these agencies in 2003 and 2004.

In September 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleged that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC sought civil penalties, restitution and disgorgement of benefits. We responded to the complaint in September 2004. In January 2005, we reached settlement agreements totaling $81 million with the CFTC, the U.S. Department of Justice and the FERC regarding investigations of past gas price reporting and gas storage activities, these being all agencies known still to be then investigating these matters as to AEP. Our settlements do not admit nor should they be construed as an admission of violation of any applicable regulation or law. We made settlement payments to the agencies in the first quarter of 2005 in accordance with the respective contractual terms. The agencies have ended their investigations and the CFTC litigation filed in September 2003 has also ended. During 2003 and 2004, we provided for the settlements payment in the amounts of $45 million and $36 million (nondeductible for federal income tax purposes), respectively. We do not expect any impact on 2005 results of operations as a result of these investigations and settlements.

8. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered subsequent to December 31, 2002 in accordance with FIN 45 Guarantors Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. We issued all of these LOCs in our ordinary course of business. At December 31, 2004, the maximum future payments for all the LOCs are approximately $242 million with maturities ranging from February 2005 to January 2011. As the parent of various subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

CSW Energy and CSW International, our subsidiaries, have guaranteed 50% of the required debt service reserve of Sweeny Cogeneration L.P. (Sweeny), an IPP of which CSW Energy is a 50% owner. The guarantee was provided in lieu of Sweeny funding the debt reserve as a part of a financing. In the event that Sweeny does not make the required debt payments, CSW Energy and CSW International have a maximum future payment exposure of approximately $4 million, which expires June 2020.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCos total future maximum payment exposure is approximately $53 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2004, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

Effective July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and 2003, we entered into several sale agreements discussed in Note 10. These sale agreements include indemnifications with a maximum exposure of approximately $970 million. There are no material liabilities recorded for any indemnifications entered during 2004 or 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2004, the maximum potential loss for these lease agreements was approximately $42 million ($27 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 16 for disclosure of other lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in our business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 1,120 terminated employees totaling $75 million pretax was recorded in the fourth quarter of 2002. Of this amount, we paid $10 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2004 or 2003. The remaining SEI related payments were made in 2003. The termination benefits expense is classified as Maintenance and Other Operation expense on our Consolidated Statements of Operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2002

Acquisition of Nordic Trading (Investments - UK Operations segment)

In January 2002, we acquired the trading operations, including key staff, of Enron's Norway and Sweden-based energy trading businesses (Nordic Trading). Results of operations are included in our Consolidated Statements of Operations from the date of acquisition. In the fourth quarter of 2002, a decision was made to exit this noncore European trading business . The sale of Nordic Trading in the second quarter of 2003 is discussed in the Dispositions section of this note.

Acquisition of USTI (Investments - Other segment)

In January 2002, we acquired 100% of the stock of United Sciences Testing, Inc. (USTI) for $13 million. USTI provides equipment and services related to automated emission monitoring of combustion gases to both our affiliates and external customers. Results of operations are included in our Consolidated Statements of Operations from the date of acquisition.

DISPOSITIONS

2004

Pushan Power Plant (Investments - Other segment)

In the fourth quarter of 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner. A purchase and sale agreement was signed in the fourth quarter of 2003. The sale was completed in March 2004 for $61 million. An estimated pretax loss on disposal of $20 million ($13 million net of tax) was recorded in December 2002, based on an indicative price expression at that time, and was classified in Discontinued Operations. The effect of the sale on our 2004 results of operations was not significant.

Results of operations of Pushan have been classified as Discontinued Operations in our Consolidated Statements of Operations. The assets and liabilities of Pushan have been included in Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held For Sale, respectively, on our Consolidated Balance Sheets at December 31, 2003. See Discontinued Operations and Assets Held for Sale sections of this note for additional information.

LIG Pipeline Company and its Subsidiaries (Investments - Gas Operations segment)

As a result of our 2003 decision to exit our noncore businesses, we actively marketed LIG Pipeline Company which had approximately 2,000 miles of natural gas gathering and transmission pipelines in Louisiana and five gas processing facilities that straddle the system. After receiving and analyzing initial bids during the fourth quarter of 2003, we recorded a pretax impairment loss of $134 million ($99 million net of tax); of this pretax loss, $129 million relates to the impairment of goodwill and $5 million relates to other charges. In January 2004, a decision was made to sell LIGs pipeline and processing assets separate from LIGs gas storage assets. (See Jefferson Island Storage & Hub, LLC section of this note for further information.) In February 2004, we signed a definitive agreement to sell LIG Pipeline Company, which owned all of the pipeline and processing assets of LIG. The sale of LIG Pipeline Company and its assets for $76 million was completed in April 2004 and the impact on results of operations in 2004 was not significant. The assets and liabilities of LIG are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets at December 31, 2003. The results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations in our Consolidated Statements of Operations. See Discontinued Operations and Assets Held for Sale sections of this note for additional information.

Jefferson Island Storage & Hub, LLC (Investments - Gas Operations segment)

In August 2004, a definitive agreement was signed to sell the gas storage assets of Jefferson Island Storage & Hub, LLC (JISH). The sale of JISH and its assets for $90 million was completed in October 2004. The sale resulted in a pretax loss of $12 million ($2 million net of tax). The assets and liabilities of JISH are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets at December 31, 2003. The results of operations and loss on sale of JISH are classified as Discontinued Operations in our Consolidated Statements of Operations. See Discontinued Operations and Assets Held for Sale sections of this note for additional information.

AEP Coal, Inc. (Investments - Other segment)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as Quaker Coal and renamed AEP Coal, Inc. During 2002, the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production is expected to continue below historical levels. In December 2002, a probability-weighted discounted cash flow analysis of fair value of the mines was performed which indicated a 2002 pretax impairment loss of $60 million including a goodwill impairment of $4 million. This impairment loss is included in Asset

Impairments and Other Related Charges on our Consolidated Statements of Operations.

In 2003, as a result of managements decision to exit our noncore businesses, we retained an advisor to facilitate the sale of AEP Coal, Inc. In the fourth quarter of 2003, after considering the current bids and all other options, we recorded a pretax charge of $67 million ($44 million net of tax) comprised of a $30 million asset impairment, a $25 million charge related to accelerated remediation cost accruals and a $12 million charge (accrued at December 31, 2003) related to a royalty agreement. These impairment losses were included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The assets and liabilities of AEP Coal, Inc. that are held for sale have been included in Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets at December 31, 2003.

In March 2004, an agreement was reached to sell assets, exclusive of certain reserves and related liabilities, of the mining operations of AEP Coal, Inc. We received approximately $9 million cash and the buyer assumed an additional $11 million in future reclamation liabilities. We retained an estimated $37 million in future reclamation liabilities. The sale closed in April 2004 and the effect of the sale on our 2004 results of operations was not significant. See Assets Held for Sale section of this note for additional information.

Independent Power Producers (Investments - Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method (two located in Colorado and two located in Florida). Our two Colorado investments included a 47.75% interest in Brush II, a 68-megawatt, gas-fired, combined cycle, cogeneration plant in Brush, Colorado and a 50% interest in Thermo, a 272-megawatt, gas-fired, combined cycle, cogeneration plant located in Ft. Lupton, Colorado. Our two Florida investments included a 46.25% interest in Mulberry, a 120-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida and a 50% interest in Orange, a 103-megawatt, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida. In accordance with GAAP, we were required to measure the impairment of each of these four investments individually. Based on indicative bids, it was determined that an other than temporary impairment existed on the two equity method investments located in Colorado. A pretax impairment of $70 million ($46 million net of tax) was recorded in September 2003 as the result of the measurement of fair value that was triggered by our decision to sell these assets. This loss of investment value was included in Investment Value Losses on our Consolidated Statements of Operations for the period ending December 31, 2003.

In March 2004, we entered into an agreement to sell the four domestic IPP investments for a total sales price of $156 million, subject to closing adjustments. An additional pretax impairment of $2 million was recorded in June 2004 (recorded to Investment Value Losses) to decrease the carrying value of the Colorado plant investments to their estimated sales price, less selling expenses. We closed on the sale of the two Florida investments and the Brush II plant in Colorado in July 2004. The sale resulted in a pretax gain of $105 million ($64 million net of tax) generated primarily from the sale of the two Florida IPPs which were not originally impaired. The gain was recorded to Gain on Disposition of Equity Investments, Net in our 2004 Consolidated Statements of Operations. The sale of the Ft. Lupton, Colorado plant closed in October 2004 and did not have a significant effect on our 2004 results of operations. Prior to the completion of the sale of each of the four IPPs, the assets for each of the four IPPs have been included in Investments in Power and Distribution Projects.

U.K. Generation (Investments - UK Operations segment)

In December 2001, we acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future. As a result, the U.K. Generation fixed asset carrying value at year-end 2002 was substantially impaired. A December 2002 probability-weighted discounted cash flow analysis of the fair value of our U.K. Generation indicated a 2002 pretax impairment loss of $549 million ($414 million net of tax). This impairment loss is included in Discontinued Operations on our Consolidated Statements of Operations for the year ended December 31, 2002.

In the fourth quarter of 2003, the U.K. generation plants were determined to be noncore assets and management engaged an investment advisor to assist in determining the best methodology to exit the U.K. business. Based on bids received and other market information, we recorded a pretax charge of $577 million ($375 net of tax), including asset impairments of $421 million during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional pretax charges of $157 million were also recorded in December 2003, including $122 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income (Loss) that were reclassified into earnings as a result of managements determination that the hedged event was no longer probable of occurring and $35 million related to a first quarter of 2004 sale of certain power contracts. All write downs related to the U.K. that were booked in the fourth quarter of 2003 were included in Discontinued Operations of our Consolidated Statements of Operations for the year ended December 31, 2003. The assets and liabilities of U.K. Generation have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our December 31, 2003 Consolidated Balance Sheets.

In July 2004, we completed the sale of substantially all operations and assets within the U.K. The sale included our two coal-fired generation plants (Fiddlers Ferry and Ferrybridge), related coal assets, and a number of related commodities contracts for approximately $456 million. The sale resulted in a pretax gain of $266 million ($128 million net of tax). As a result of the sale, the buyer assumed an additional $46 million in future reclamation liabilities and $10 million in pension liabilities. The remaining assets and liabilities include certain physical power and capacity positions and financial coal and freight swaps. Substantially all of these positions mature or have been settled with the applicable counterparties during the first quarter of 2005. The results of operations and gain on sale are included in Discontinued Operations on our Consolidated Statements of Operations for the year ended December 31, 2004. See Discontinued Operations and Assets Held for Sale sections of this note for additional information.

Texas Plants - TCC and TNC Generation Assets (Utility Operations segment)

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability-must-run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOTs approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to renew RMR contracts at the six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOTs 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate the TNC plants, a pretax write-down of utility assets of approximately $34 million was recorded in Asset Impairments and Other Related Charges expense during the third quarter of 2002 on our Consolidated Statements of Operations. The decision to deactivate the TCC plants resulted in a pretax write-down of utility assets of approximately $96 million, which was deferred and recorded in Regulatory Assets during the third quarter of 2002 in our Consolidated Balance Sheets.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional pretax asset impairment charge to Asset Impairments and Other Related Charges expense of $4 million in the fourth quarter of 2002. In addition, TNC recorded related fuel inventory and materials and supplies write-downs of $3 million ($1 million in Fuel for Electric Generation and $2 million in Maintenance and Other Operation). Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in Regulatory Assets in the fourth quarter of 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in Regulatory Assets.

The total Texas plant pretax asset impairment of $38 million in 2002 (all related to TNC) is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, we recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets of Discontinued Operations and Held for Sale on our Consolidated Balance Sheets. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding. As a result of the True-up Proceeding, if we are unable to recover all or a portion of our requested costs (see Net Stranded Generation Costs section of Note 6), any unrecovered costs could have a material adverse effect on our results of operations, cash flows and possibly financial condition.

In March 2004, we signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on our results of operations during the period ended December 31, 2004.

In December 2004, we recorded a pretax deduction of $185 million ($121 million net of tax) related to the TCC true-up regulatory asset for stranded generation plant costs (see Net Stranded Generation Costs section of Note 6). This deduction is shown as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax on our 2004 Consolidated Statements of Operations.

The remaining generation assets and liabilities of TCC are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on our Consolidated Balance Sheets. See Assets Held for Sale section of this note for additional information.

South Coast Power Limited (Investments - Other Segment)

South Coast Power Limited (SCPL) is a 50% owned venture that was formed in 1996 to build, own and operate Shoreham Power Station, a 400-megawatt, combined-cycle, gas turbine power station located in Shoreham, England. In 2002, SCPL was subject to adverse wholesale electric power rates. A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pretax other than temporary impairment of the equity interest in the amount of $63 million. This loss of investment value was included in Investment Value Losses in the 2002 Consolidated Statements of Operations.

In the fourth quarter of 2003, management determined that our U.K. operations were no longer part of our core business and as a result, a decision was made to exit the U.K. market. In September 2004, we completed the sale of our 50% ownership in SCPL for $47 million, resulting in a pretax gain of $48 million ($31 million net of tax) in the third quarter of 2004. This gain was recorded to Gain on Disposition of Equity Investments, Net in our Consolidated Statements of Operations for the period ended December 31, 2004. The gain reflects improved conditions in the U.K. power market.

Excess Real Estate (Investments - Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, Texas obtained through our merger with CSW in June 2000. One prospective buyer executed an option to purchase the building. The sale of the facility was projected by second quarter of 2003 and an estimated 2002 pretax loss on disposal of $16 million was recorded, based on the option sale price. The estimated loss was included in Asset Impairments and Other Related Charges in our 2002 Consolidated Statements of Operations. We recorded an additional pretax impairment of $6 million in Maintenance and Other Operation in our 2003 Consolidated Statements of Operations based on market data. The original prospective buyer did not complete their purchase of the building by the end of 2003, and thus, the asset no longer qualified for held for sale status. The building was then reclassified to held and used status as of December 31, 2003.

In June 2004, we entered into negotiations to sell the Dallas office building. This resulted in the asset again being classified as held for sale in the second quarter of 2004. An additional pretax impairment of $3 million was recorded in Maintenance and Other Operation expense during the second quarter of 2004 to write down the value of the office building to the current estimated sales price, less estimated selling expenses. In October 2004, we completed the sale of the Dallas office building for $8 million. The sale did not have a significant effect on our results of operations. The property asset of $12 million at December 31, 2003 has been classified on our Consolidated Balance Sheets as Assets of Discontinued Operations and Held for Sale. See Assets Held for Sale section of this note for additional information.

Numanco LLC (Investments - Other segment)

In November 2004, we completed the sale of Numanco LLC for a sale price of $25 million. Numanco was a provider of staffing services to the utility industry. The sale did not have a significant effect on our 2004 results of operations.

2003

C3 Communications (Investments - Other segment)

In February 2003, C3 Communications sold the majority of its assets for a sales price of $7 million. We provided for a pretax asset impairment of $82 million ($53 million net of tax) in December 2002 and the effect of the sale on 2003 results of operations was not significant. The impairment is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

Mutual Energy Companies (Utility Operations segment)

On December 23, 2002, we sold the general partner interests and the limited partner interests in Mutual Energy CPL LP and Mutual Energy WTU LP for a base purchase price paid in cash at closing and certain additional payments, including a net working capital payment. The buyer paid a base purchase price of $146 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. We recorded a pretax gain of $129 million ($84 million net of tax) in Other Income during 2002. We provided the buyer with a power supply contract for the two REPs and back-office services related to these customers for a two-year period. In addition, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market develops increased earnings opportunities. No revenue was recorded in 2004 and 2003 related to these sharing agreements, pending resolution of various contracted matters. Under the Texas Restructuring Legislation, REPs are subject to a clawback liability if customer change does not attain thresholds required by the legislation. We are responsible for a portion of such liability, if any, for the period we operated the REPs in the Texas competitive retail market (January 1, 2002 through December 23, 2002). In addition, we retained responsibility for regulatory obligations arising out of operations before closing. Our wholly-owned subsidiary, Mutual Energy Service Company LLC (MESC), received an up-front payment of approximately $30 million from the buyer associated with the back-office service agreement, and MESC deferred its right to receive payment of an additional amount of approximately $9 million to secure certain contingent obligations. These prepaid service revenues were deferred on the books of MESC as of December 31, 2002 and were amortized over the two-year term of the back-office service agreement.

In February 2003, we completed the sale of MESC for $30 million dollars and realized a pretax gain of approximately $39 million, which included the recognition of the remaining balance of the original prepayment of $30 million ($27 million), as no further service obligations existed for MESC. This gain was recorded in Other Income in our Consolidated Statements of Operations.

Water Heater Assets (Utility Operations segment)

We sold our water heater rental program for $38 million and recorded a pretax loss of $4 million in the first quarter of 2003 based upon final terms of the sale agreement. We had provided for a pretax charge of $7 million in the fourth quarter of 2002 based on an estimated sales price ($3 million asset impairment charge and $4 million lease prepayment penalty). The impairment loss is included in Investment Value Losses in our Consolidated Statements of Operations. We operated a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale.

AEP Gas Power Systems LLC (Investments - Other segment)

In 2001, we acquired a 75% interest in a startup company, seeking to develop low-cost peaking generator sets powered by surplus jet turbine engines. In January 2003, AEP Gas Power Systems LLC sold its assets. We recognized a pretax goodwill impairment loss of $12 million in the first quarter of 2002 based on cash flow studies that reflect technological and operational problems associated with the underlying technology (also see Goodwill section of Note 3). The impairment loss was recorded in Investment Value Losses on our Consolidated Statements of Operations. The effect of the asset sale on the 2003 results of operations was not significant.

Newgulf Facility (Investments - Other segment)

In 1995, we purchased an 85 MW gas-fired peaking electrical generation facility located near Newgulf, Texas (Newgulf). In October 2002, we began negotiations with a likely buyer of the facility. We estimated a pretax loss on sale of $12 million based on the indicative bid. This loss was recorded as Asset Impairments and Other Related Charges on our Consolidated Statements of Operations during the fourth quarter of 2002. During the second quarter of 2003, we completed the sale of Newgulf and the impact on earnings in 2003 was not significant.

Nordic Trading (Investments - UK Operations segment)

In October 2002, we announced that our ongoing energy trading operations would be centered around our generation assets. As a result, we took steps to exit our coal, gas and electricity trading activities in Europe with the exception of those activities predominantly related to our U.K. generation operations. The Nordic Trading business acquired earlier in 2002 was made available for sale to potential buyers later in 2002. The estimated pretax loss on disposal recorded in 2002 of $5 million consisted of impairment of goodwill of $4 million and impairment of assets of $1 million. The estimated loss of $5 million is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. Managements determination of a zero fair value was based on discussions with a potential buyer. The transfer of the Nordic Trading business, including the trading portfolio, to new owners was completed during the second quarter of 2003 and the impact on earnings during 2003 was not significant.

Eastex (Investments - Other segment)

In 1998, we began construction of a natural gas-fired cogeneration facility (Eastex) located near Longview, Texas and commercial operations commenced in December 2001. In June 2002, we requested that the FERC allow us to modify the FERC Merger Order and substitute Eastex as a required divestiture under the order due to the fact that the agreed upon market-power related divestiture of a plant in Oklahoma was no longer feasible. The FERC approved the request at the end of September 2002. Subsequently, in the fourth quarter of 2002, we solicited bids for the sale of Eastex and several interested buyers were identified by December 2002. The estimated pretax loss on the sale of $219 million ($142 million net of tax), which was based on the estimated fair value of the facility and indicative bids by interested buyers, was recorded in Discontinued Operations in our Consolidated Statements of Operations during the fourth quarter of 2002.

We completed the sale of Eastex during the third quarter of 2003 and the effect of the sale on 2003 results of operations was not significant. The results of operations of Eastex have been reclassified as Discontinued Operations in accordance with SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, for all years presented. See the Discontinued Operations section of this note for additional information.

Grupo Rede Investment (Investments - Other segment)

In December 2002, we recorded a pretax other than temporary impairment loss of $217 million ($141 million net of tax) of our 44% equity investment in Vale and our 20% equity interest in Caiua, both Brazilian electric operating companies (referred to as Grupo Rede). This impairment was due to the continuing decline in the Brazilian economy and currency which increased credit risks within Grupo Rede. This amount is included in Investment Value Losses on our 2002 Consolidated Statements of Operations.

In December 2003, we transferred our share and investment in Vale to Grupo Rede for $1 million. The effect of the transfer on our 2003 results of operations was not significant.

Excess Equipment (Investments - Other segment)

In November 2002, as a result of a cancelled development project, we obtained title to a surplus gas turbine generator. We were unsuccessful in finding potential buyers of the unit due to an over-supply of generation equipment available for sale during 2002. An estimated pretax loss on disposal of $24 million was recorded in December 2002, based on market prices of similar equipment. The loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

We completed the sale of the surplus gas turbine generator in November 2003. The proceeds from the sale were $9 million. A pretax loss of $2 million was recorded in the fourth quarter of 2003.

Ft. Davis Wind Farm (Investments - Other segment)

In the 1990s, we developed a 6 MW wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002, our engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility was completed in 2004. An estimated pretax loss on abandonment of $5 million was recorded in December 2002. The loss was recorded in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

2002

SEEBOARD (Investments - Other segment)

On June 18, 2002, through a wholly-owned subsidiary, we entered into an agreement, subject to European Union (EU) approval, to sell our consolidated subsidiary SEEBOARD, a U.K. electricity supply and distribution company. EU approval was received July 25, 2002 and the sale was completed on July 29, 2002. We received approximately $941 million in net cash from the sale, subject to a working capital true-up, and the buyer assumed SEEBOARD debt of approximately $1.1 billion, resulting in a net loss of $345 million at June 30, 2002. The results of operations of SEEBOARD have been classified as Discontinued Operations for all years presented. A pretax net loss of $22 million ($14 million net of tax) was classified as Discontinued Operations in the second quarter of 2002. The remaining $323 million of the net loss has been classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Goodwill and Other Intangible Assets section of Note 2 and Goodwill section of Note 3) and has been reported as a Cumulative Effect of Accounting Change retroactive to January 1, 2002. A $59 million pretax reduction of the net loss ($38 million net of tax) was recognized in the second half of 2002 to reflect changes in exchange rates to closing, settlement of working capital true-up and selling expenses. The total net loss recognized on the disposal of SEEBOARD was $286 million. Proceeds from the sale of SEEBOARD were used to pay down bank facilities and short-term debt. See Discontinued Operations section of this note for additional information.

CitiPower (Investments - Other segment)

On July 19, 2002, through a wholly-owned subsidiary, we entered into an agreement to sell CitiPower, a retail electricity and gas supply and distribution subsidiary in Australia. We completed the sale on August 30, 2002 and received net cash of approximately $175 million and the buyer assumed CitiPower debt of approximately $674 million. We recorded a pretax charge of $192 million ($125 million net of tax) as of June 30, 2002. The charge included a pretax impairment loss of $151 million ($98 million net of tax) on the remaining carrying value of an intangible asset related to a distribution license for CitiPower. The remaining $41 million pretax net loss ($27 million net of tax) was classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Goodwill and Other Intangible Assets section of Note 2 and Goodwill section of Note 3) and was recorded as a Cumulative Effect of Accounting Change retroactive to January 1, 2002.

The pretax loss on the sale of CitiPower increased $37 million ($24 million net of tax) to $229 million ($149 million net of tax; $122 million plus $27 million of cumulative effect) in the second half of 2002 based on actual closing amounts and exchange rates. See the Discontinued Operations section of this note for additional information.

DISCONTINUED OPERATIONS

Management periodically assesses the overall AEP business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified as Assets and Liabilities of Discontinued Operations and Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and have been classified as such in 2004, 2003 and 2002. Results of operations of these businesses have been classified as shown in the following table (in millions):

	SEEBOARD	CitiPower	Eastex	Pushan Power Plant	LIG (a)	U.K. Generation	Total
2004 Revenue	$ -	$ -	$ -	$ 10	$ 165	$ 125	$ 300
2004 Pretax Income (Loss)	(3)	-	-	9	(12)	164	158
2004 Earnings (Loss), Net of Tax	(2)	-	-	6	(12)	91 (b)	83
2003 Revenue	-	-	58	60	653	125	896
2003 Pretax Income (Loss)	-	(20)	(23)	4	(122)	(713)	(874)
2003 Earnings (Loss), Net of Tax	16	(13)	(14)	5	(91)	(508)(c)	(605)
2002 Revenue	694	204	73	57	507	251	1,786
2002 Pretax Income (Loss)	180	(190)	(239)	(13)	14	(579)	(827)
2002 Earnings (Loss), Net of Tax	96	(123)	(156)	(7)	8	(472)(d)	(654)

(a) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.

(b) Earnings per share related to the UK Operations was $0.23.
(c) Earnings per share related to the UK Operations was $(1.32).
(d) Earnings per share related to the UK Operations was $(1.42).

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2004, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $18 million ($15 million related to Investment Value Losses, and $3 million related to charges recorded for Excess Real Estate in Maintenance and Other Operation in the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

In 2003, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $1.4 billion [consisting of approximately $650 million related to Asset Impairments of $610 million and Other Related Charges of $40 million, $70 million related to Investment Value Losses, $711 million related to Discontinued Operations ($550 million of impairments and $161 million of other charges) and $6 million related to charges recorded for Excess Real Estate in Maintenance and Other Operation in the Consolidated Statements of Operations] that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit noncore businesses and other factors.

In 2002, AEP recorded pretax impairments of assets (including goodwill) and investments totaling $1.7 billion (consisting of approximately $318 million related to Asset Impairments, $321 million related to Investment Value Losses, $938 million related to Discontinued Operations and $88 million related to charges recorded in other lines within the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional goodwill impairment loss from adoption of SFAS 142 (see Goodwill and Other Intangible Assets section of Note 2).

The categories of impairments and gains on dispositions include:

	2004	2003	2002
		(in millions)	
Asset Impairments and Other Related Charges (Pretax)			
AEP Coal, Inc.	$ -	$ 67	$ 60
HPL and Other	-	315	-
Power Generation Facility	-	258	-
Blackhawk Coal Company	-	10	-
Ft. Davis Wind Farm	-	-	5
Texas Plants	-	-	38
Newgulf Facility	-	-	12
Excess Equipment	-	-	24
Nordic Trading	-	-	5
Excess Real Estate	-	-	16
Telecommunications - AEPC/C3	-	-	158
Total	$ -	$ 650	$ 318
Investment Value Losses (Pretax)			
Independent Power Producers	$ (2)	$ (70)	$ -
Bajio	(13)	-	-
Water Heater Assets	-	-	(3)
South Coast Power Investment	-	-	(63)
Telecommunications - AFN	-	-	(14)
AEP Gas Power Systems	-	-	(12)
Grupo Rede Investment - Vale	-	-	(217)
Technology Investments	-	-	(12)
Total	$ (15)	$ (70)	$ (321)
Gain on Disposition of Equity Investments, Net			
Independent Power Producers	$ 105	$ -	$ -
South Coast Power Investment	48	-	-
Total	$ 153	$ -	$ -
Impairments and Other Related Charges and Operations Included in Discontinued Operations (Net of tax)			
Impairments and Other Related Charges:			
U.K. Generation Plants	$ -	$ (375)	$ (414)
Louisiana Intrastate Gas (a)	-	(99)	-
CitiPower	-	-	(122)
Eastex	-	-	(142)
SEEBOARD	-	-	24
Pushan	-	-	(13)
Total (b)	$ -	$ (474)	$ (667)
Operations:			
U.K. Generation Plants	$ 91	$ (133)	$ (58)
Louisiana Intrastate Gas (a)	(12)	8	8
CitiPower	-	(13)	(1)
Eastex	-	(14)	(14)
SEEBOARD	(2)	16	72
Pushan	6	5	6
Total	$ 83	$ (131)	$ 13
Total Discontinued Operations	$ 83	$ (605)	$ (654)

(a) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.

(b) See the Dispositions and Discontinued Operations sections of this note for the pretax impairment figures.

ASSETS HELD FOR SALE

Texas Plants - Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCCs 7.81% share of Oklaunion Power Station for approximately $43 million, subject to closing adjustments, to an unrelated party. In May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCCs 7.81% ownership of the Oklaunion Power Station. One of these agreements is currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners exercise of their rights of first refusal void. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCCs assets and liabilities related to the Oklaunion Power Station have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets as of December 31, 2004 and 2003.

Texas Plants - South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCCs 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCCs 25.2% share of the STP nuclear plant. We do not expect the sale to have a significant effect on our future results of operations. We expect the sale to close in the first six months of 2005. TCCs assets and liabilities related to STP have been classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, in our Consolidated Balance Sheets as of December 31, 2004 and 2003.

The Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale at December 31, 2004 and 2003 are as follows:

December 31, 2004	**Texas Plants**
Assets:	**(in millions)**
Other Current Assets	$ 24
Property, Plant and Equipment, Net	413
Regulatory Assets	48
Nuclear Decommissioning Trust Fund	143
Total Assets of Discontinued Operations and Held for Sale	$ 628
Liabilities:	
Regulatory Liabilities	$ 1
Asset Retirement Obligations	249
Total Liabilities of Discontinued Operations and Held for Sale	$ 250

December 31, 2003	AEP Coal	Pushan Power Plant	LIG (excluding Jefferson Island)	Excess Real Estate	Jefferson Island	U.K. Generation	Texas Plants	Total
					(in millions)			
Assets:								
Current Risk Management Assets	$ -	$ -	$ -	$ -	$ -	$ 560	$ -	$ 560
Other Current Assets	6	24	49	-	1	685	57	822
Property, Plant and Equipment, Net	13	142	109	12	62	99	797	1,234
Regulatory Assets	-	-	-	-	-	-	49	49
Decommissioning Trusts	-	-	-	-	-	-	125	125
Goodwill	-	-	1	-	14	-	-	15
Long-term Risk Management Assets	-	-	-	-	-	274	-	274
Other	-	-	8	-	1	6	-	15
Total Assets of Discontinued Operations and Held for Sale	$ 19	$ 166	$ 167	$ 12	$ 78	$ 1,624	$ 1,028	$ 3,094
Liabilities:								
Current Risk Management Liabilities	$ -	$ -	$ 15	$ -	$ -	$ 767	$ -	$ 782
Other Current Liabilities	-	26	42	-	4	221	-	293
Long-term Debt	-	20	-	-	-	-	-	20
Long-term Risk Management Liabilities	-	-	-	-	-	435	-	435
Regulatory Liabilities	-	-	-	-	-	-	9	9
Asset Retirement Obligations	11	-	-	-	-	29	219	259
Employee Pension Obligations	-	-	-	-	-	12	-	12
Deferred Credits and Other	3	57	6	-	-	-	-	66
Total Liabilities of Discontinued Operations and Held for Sale	$ 14	$ 103	$ 63	$ -	$ 4	$ 1,464	$ 228	$ 1,876

ASSETS HELD AND USED

In 2003 and 2002, we recorded the following impairments related to assets held and used (including goodwill) to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations as discussed below:

HPL and Other (Investments - Gas Operations segment)

HPL owns, or leases, and operates natural gas gathering, transportation and storage operations in Texas. In 2003, management announced that we were in the process of divesting our noncore assets, which includes the assets within our Investments-Gas Operations segment. During the fourth quarter of 2003, based on a probability-weighted, net of tax cash flow analysis of the fair value of HPL, we recorded a pretax impairment of $300 million ($218 million net of tax). This impairment included a pretax impairment of $150 million related to goodwill, reflecting managements decision not to operate HPL as a major trading hub. The cash flow analysis used managements estimate of the alternative likely outcomes of the uncertainties surrounding the continued use of the Bammel facility and other matters (see Enron Bankruptcy section of Note 7) and a net of tax risk free discount rate of 3.3% over the remaining life of the assets.

We also recorded a pretax charge of $15 million ($10 million net of tax) in the fourth quarter of 2003. This impairment is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. This charge related to the effect of the write-off of certain HPL and LIG assets and the impairment of goodwill related to our former optimization strategy of LIG assets by AEP

Energy Services.

The total HPL pretax impairment of $315 million in 2003 is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

See Note 19 for additional discussion of the sale of HPL in 2005.

Blackhawk Coal Company (Utility Operations segment)

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting managements decision not to pursue development of potential gas reserves. As a result, a pretax charge of $10 million was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

Power Generation Facility (Investments - Other segment)

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company.

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation. In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2004 and 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since Junipers funded obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the table of future minimum lease payments in Note 16.

The uncertainty of the litigation between Tractebel Energy Marketing, Inc. (TEM) and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a pretax impairment of $258 million ($168 million net of tax) in December 2003. The impairment was recorded to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

See further discussion in Power Generation Facility section of Note 7.

OTHER LOSSES

2004

Compresion Bajio S de R.L. de C.V. (Investments - Other segment)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600-megawatt power plant in Mexico. Due to the decision to divest noncore assets, we began marketing our investment in Bajio to potential buyers in the third quarter of 2003.

In December 2004, on the basis of an indicative bid by a prospective buyer, an estimated pretax other than temporary impairment of $13 million was recorded for Bajio and classified in Investment Value Losses on our Consolidated Statements of Operations.

2002

Telecommunications (Investments - Other segment)

We developed businesses to provide telecommunication services to businesses and other telecommunication companies through broadband fiber optic networks. The businesses included AEP Communications, LLC (AEPC), C3 Communications, Inc. (C3), and a 50% share of AFN, LLC (AFN), a joint venture. Due to the difficult economic conditions in these businesses and the overall telecommunications industry, the AEP Board approved in December 2002 a plan to cease operations of these businesses. We took steps to market the assets of the businesses to potential interested buyers in the fourth quarter of 2002.

We completed the sale of substantially all the assets of C3 in the first quarter of 2003 as discussed in the Dispositions section of this note. AFN closed on the sale of substantially all of its assets in January 2004 with no significant additional effect on results of operations in 2004. The sale of remaining telecommunication assets is proceeding.

An estimated pretax impairment loss of $158 million ($76 million related to AEPC and $82 million related to C3) was recorded in December 2002 and is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations. An estimated pretax loss in value of the investment in AFN of $14 million was recorded in December 2002 and is classified in Investment Value Losses in our Consolidated Statements of Operations. The estimated losses were based on indicative bids by potential buyers.

Technology Investments (Investments - Other segment)

We previously made investments totaling $12 million in four early-stage or startup technologies involving pollution control and procurement. An analysis in December 2002 of the viability of the underlying technologies and the projected performance of the investee companies indicated that the investments were unlikely to be recovered, and an other than temporary impairment of the entire amount of the equity interest under APB 18, The Equity Method of Accounting for Investments in Common Stock, was recorded. The loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations.

11. BENEFIT PLANS

In the U.S. we sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees in the U.S. are covered by either one qualified plan or both a qualified and a nonqualified pension plan. Other postretirement benefit plans are sponsored by us to provide medical and life insurance benefits for retired employees in the U.S. We implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004 (see FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003 section of Note 2). The Medicare subsidy reduced our FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. The tax-free subsidy reduced 2004s net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

We also had a foreign pension plan for employees of AEP Energy Services UK Generation Limited (Genco) in the U.K. The Genco pension plan had $7 million of accumulated benefit obligations in excess of plan assets at December 31, 2002. The plan was in an overfunded position at December 31, 2003. The plan was transferred in 2004 in conjunction with the sale of the U.K. generation assets.

The following tables provide a reconciliation of the changes in the plans projected benefit obligations and fair value of assets over the two-year period ending at the plans measurement date of December 31, 2004, and a statement of the funded status as of December 31 for both years:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
			(in millions)	
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 3,688	$ 3,583	$ 2,163	$ 1,877
Service Cost	86	80	41	42
Interest Cost	228	233	117	130
Participant Contributions	-	-	18	14
Actuarial (Gain) Loss	379	91	(130)	192
Benefit Payments	(273)	(299)	(109)	(92)
Projected Obligation at December 31	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,180	$ 2,795	$ 950	$ 723
Actual Return on Plan Assets	409	619	98	122
Company Contributions (a)	239	65	136	183
Participant Contributions	-	-	18	14
Benefit Payments (a)	(273)	(299)	(109)	(92)
Fair Value of Plan Assets at December 31	$ 3,555	$ 3,180	$ 1,093	$ 950
Funded Status:				
Funded Status at December 31	$ (553)	$ (508)	$ (1,007)	$ (1,213)
Unrecognized Net Transition Obligation	-	2	179	206
Unrecognized Prior Service Cost (Benefit)	(9)	(12)	5	6
Unrecognized Net Actuarial Loss	1,040	797	795	977
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

(a) Our contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Amounts Recognized in the Balance Sheet as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
			(in millions)	
Prepaid Benefit Costs	$ 524 (a)	$ 325	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(28)	(24)
Additional Minimum Liability	(566)	(723)	N/A	N/A
Intangible Asset	36	39	N/A	N/A
Pretax Accumulated Other Comprehensive Income	530	684	N/A	N/A
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

N/A = Not Applicable

(a) Includes $386 million related to the qualified plan that became fully funded upon receipt of the December 2004 discretionary contribution.

Pension and Other Postretirement Plans Assets:

The asset allocations for our pension plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2005	**2004**	**2003**
Asset Category		**(in percentage)**	
Equity Securities	70	68	71
Debt Securities	28	25	27
Cash and Cash Equivalents	2	7	2
Total	100	100	100

The asset allocations for our other postretirement benefit plans at the end of 2004 and 2003, and target allocation for 2005, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2005	**2004**	**2003**
Asset Category		**(in percentage)**	
Equity Securities	70	70	61
Debt Securities	28	28	36
Other	2	2	3
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Because of a $200 million discretionary contribution at the end of 2004, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2005.

The value of our pension plans assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The qualified plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits).

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation:	**2004**	**2003**
	(in millions)	
Qualified Pension Plans	$ 3,918	$ 3,549
Nonqualified Pension Plans	80	76
Total	$ 3,998	$ 3,625

Minimum Pension Liability:

Our combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $553 million at December 31, 2004. For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2004 and 2003 were as follows:

	Underfunded Pension Plans	
	2004	**2003**
End of Year	**(in millions)**	
Projected Benefit Obligation	$ 2,978	$ 3,688
Accumulated Benefit Obligation	2,880	3,625
Fair Value of Plan Assets	2,406	3,180
Accumulated Benefit Obligation Exceeds theFair Value of Plan Assets	474	445

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2004	**2003**
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

We made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intend to make additional discretionary contributions of approximately $100 million per quarter in 2005 to meet our goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations:

The weighted-average assumptions as of December 31, used in the measurement of our benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
			(in percentages)	
Discount Rate	5.50	6.25	5.80	6.25
Rate of Compensation Increase	3.70	3.70	N/A	N/A

The method used to determine the discount rate that we utilize for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moodys AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, we changed to a duration based methodin whicha hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed with a durationmatching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for pension plans and 5.80% for other postretirement benefit plans.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Estimated Future Benefit Payments and Contributions:

Information about the expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

	Pension Plans		Other Postretirement Benefit Plans	
Employer Contributions	**2005**	**2004**	**2005**	**2004**
			(in millions)	
Required Contributions (a)	$17	$ 31	N/A	N/A
Additional Discretionary Contributions	400 (b)	200 (b)	$ 142	$ 137

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor.

(b) Contribution in 2004 and expected contribution in 2005 in excess of the required contribution to fully fund our qualified pension plans by the end of 2005.

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans trust is generally based on the amount of the other postretirement benefit plans expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2005	$ 293	$ 115	$ -
2006	302	122	(9)
2007	317	131	(10)
2008	327	140	(11)
2009	348	151	(12)
Years 2010 to 2014, in Total	1,847	867	(72)

Components of Net Periodic Benefit Cost:

The following table provides the components of our net periodic benefit cost (credit) for the plans for fiscal years 2004, 2003 and 2002:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
			(in millions)			
Service Cost	$ 86	$ 80	$ 72	$ 41	$ 42	$ 34
Interest Cost	228	233	241	117	130	114
Expected Return on Plan Assets	(292)	(318)	(337)	(81)	(64)	(62)
Amortization of Transition (Asset) Obligation	2	(8)	(9)	28	28	29
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial (Gain) Loss	17	11	(10)	36	52	27
Net Periodic Benefit Cost (Credit)	40	(3)	(44)	141	188	142
Capitalized Portion	(10)	(3)	15	(46)	(43)	(26)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 30	$ (6)	$ (29)	$ 95	$ 145	$ 116

Actuarial Assumptions for Net Periodic Benefit Costs:

The weighted-average assumptions as of January 1, used in the measurement of our benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
				(in percentage)		
Discount Rate	6.25	6.75	7.25	6.25	6.75	7.25
Expected Return on Plan Assets	8.75	9.00	9.00	8.35	8.75	8.75
Rate of Compensation Increase	3.70	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2004 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The health care trend rate assumptions used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	**2004**	**2003**
Initial	10.0 %	10.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2009	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	**1% Decrease**
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 27	$ (21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	302	(245)

AEP Savings Plans

We sponsor various defined contribution retirement savings plans eligible to substantially all non-United Mine Workers of America (UMWA) U.S. employees. These plans include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. On January 1, 2003, the two major AEP Savings Plans merged into a single plan. Our contributions to the plan are 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled $55.0 million in 2004, $57.0 million in 2003 and $60.1 million in 2002.

Other UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2004, 2003 and 2002.

12. <u>STOCK-BASED COMPENSATION</u>

The American Electric Power System 2000 Long-Term Incentive Plan (the Plan) authorizes the use of 15,700,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was adopted in 2000 by the Board of Directors and shareholders.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance share units and stock options. Restricted stock units generally vest, subject to the participants continued employment, in approximately equal 1/3 or 1/5 increments on each of the first three or five anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. AEP awarded 105,852 and 105,910 restricted stock units, including units awarded for dividends, with weighted-average grant-date fair values of $32.03 and $22.17 per unit in 2004 and 2003, respectively. Restricted stock units were not granted prior to 2003. Compensation cost is recorded over the vesting period based on the market value on the grant date. Expense associated with units that are forfeited is reversed in the period of forfeiture.

AEP awarded 300,000 restricted shares in 2004, which vest over periods ranging from 1 to 8 years. Compensation cost is recorded over the vesting period based on the market value of $30.76 per unit on the grant date. Restricted shares were not granted prior to 2004.

Performance share units are equal in value to shares of AEP common stock but are subject to an attached performance factor ranging from 0% to 200%. The performance factor is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors. Performance share units are typically paid in cash at the end of a three-year vesting period, unless they are needed to satisfy a participants stock ownership requirement, in which case they are mandatorily deferred as phantom stock units until the end of the participants AEP career. Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participants termination of employment. AEP awarded 171,270, 1,103,542 and 167,040 performance share units, including units awarded for dividends on other units, with weighted-average grant-date fair values of $31.42, $27.94 and $42.14 per unit in 2004, 2003 and 2002, respectively. In 2004 and 2003, no performance share units were deferred into phantom stock units to satisfy stock ownership requirements. However, AEP awarded 8,809 and 14,042 additional phantom stock units as dividends on other units with weighted-average grant-date fair values of $32.92 and $25.60 per unit in 2004 and 2003, respectively. In 2002, 42,115 performance share units were deferred into phantom stock units to satisfy stock ownership requirements and 15,388 phantom stock units with a weighted-average grant-date fair value of $34.20 per unit were awarded as dividends on other units. The compensation cost for performance share units is recorded over the vesting period, and the liability for both the performance share and phantom stock unit is adjusted for changes in fair market value. Amounts equivalent to cash dividends on both performance share and phantom stock units accrue as additional units.

Under the Plan, the exercise price of all stock option grants must equal or exceed the market price of AEPs common stock on the date of grant, and in accordance with its policy, AEP does not record compensation expense. AEP does, however, anticipate adopting SFAS 123R effective July 1, 2005 which will result in the recording of compensation expense for stock options (see SFAS 123R in Note 2). AEP historically has granted options that have a ten-year life and vest, subject to the participants continued employment, in approximately equal 1/3 increments on January 1 following the first, second and third anniversary of the grant date.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled or expired. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

A summary of AEP stock option transactions in fiscal years 2004, 2003 and 2002 is as follows:

	2004			2003			2002		
	Options (in thousands)	Weighted Average Exercise Price		Options (in thousands)	Weighted Average Exercise Price		Options (in thousands)	Weighted Average Exercise Price	
Outstanding at beginning of year	9,095	$	33	8,787	$	34	6,822	$	37
Granted	149	$	31	928	$	28	2,923	$	27
Exercised	(525)	$	27	(23)	$	27	(600)	$	36
Forfeited	(489)	$	34	(597)	$	33	(358)	$	41
Outstanding at end of year	8,230	$	33	9,095	$	33	8,787		34
Options exercisable at end of year	6,069	$	35	3,909	$	36	2,481	$	36
Weighted average exercise price of options:									
Granted above Market Price			N/A			N/A		$	27
Granted at Market Price		$	31		$	28		$	27

The following table summarizes information about AEP stock options outstanding at December 31, 2004:

Options Outstanding

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price	
$25.73 - $27.95	2,833	7.3	$	27.30
$30.76 - $35.63	4,905	4.9		35.47
$43.79 - $49.00	492	6.4		46.05
	8,230	5.8		33.29

Options Exercisable

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Exercise Price	
$25.73 - $27.95	914	$	27.11
$30.76 - $35.63	4,756		35.62
$43.79 - $49.00	399		46.42
	6,069		35.05

The proceeds received from exercised stock options are included in common stock and paid-in capital.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of AEP options granted:

	2004	2003	2002
Risk Free Interest Rate	4.14 %	3.92 %	3.53 %
Expected Life	7 years	7 years	7 years
Expected Volatility	28.17 %	27.57 %	29.78 %
Expected Dividend Yield	4.84 %	4.86 %	6.15 %
Weighted average fair value of options:			
Granted above Market Price	N/A	N/A	$ 4.58
Granted at Market Price	$ 6.06	$ 5.26	$ 4.37

13. <u>BUSINESS SEGMENTS</u>

We identified our reportable segments based on the nature of the product and services and geography. Our core operations involve domestic utility operations, including generation, transmission and distribution of electric energy. Certain Investments segments are reported by product or service (Gas Operations and Other) while our Investments - UK Operations segment is distinguished by its geography. These operating segments are not aggregated.

In addition to our business operations with external customers, our business segments also provide products and services between business segments. These intersegment activities primarily consist of risk management activities and barging activities performed by our Utility Operations segment and the sale of gas by our Investments - Gas Operations segment. Our Investments - Other segment provides accounts receivable factoring, barging activities and until the second quarter of 2004, the sale of coal to our Utility Operations segment. Our All Other segment includes items such as interest related to financing costs, litigation costs on behalf of other segments and other corporate-type services.

Our current international portfolio, presented in our Investments - Other segment, includes only limited investments in the generation and supply of power in Mexico and the Pacific Rim. We sold our generation assets in the U.K. and China in 2004. In 2002, we sold our investments in international distribution companies in Australia and the U.K.

Our segments and their related business activities are as follows:

Utility Operations

Domestic generation of electricity for sale to retail and wholesale customers

Domestic electricity transmission and distribution

Investments - Gas Operations (a)

Gas and pipeline and storage services

Investments - UK Operations (b)

International generation of electricity for sale to wholesale customers

Coal procurement and transportation to AEPs U.K. plants

Investments - Other (c)

Bulk commodity barging operations, wind farms, independent power producers and other energy supply businesses

(a) Operations of LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued during 2003 and were sold during 2004. The remaining gas assets were sold during the first quarter of 2005.

(b) UK Operations were classified as discontinued during 2003 and were sold during 2004.
(c) Four independent power producers were sold during 2004.

The tables below present segment income statement information for the twelve months ended December 31, 2004, 2003 and 2002 and balance sheet information for the years ended December 31, 2004 and 2003. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current years presentation.

2004	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 10,513	$ 3,064	$ -	$ 480	$ -	$ -	$ 14,057
Other Operating Segments	120	50	-	80	7	(257)	-
Total Revenues	$ 10,633	$ 3,114	$ -	$ 560	$ 7	$ (257)	$ 14,057
Income (Loss) Before Discontinued Operations, Extraordinary Item and Cumulative Effect of AccountingChanges	$ 1,171	$ (51)	$ -	$ 78	$ (71)	$ -	$ 1,127

Discontinued Operations, Net of Tax	-	(12)	91	4	-	-	83
Extraordinary Item, Net of Tax	(121)	-	-	-	-	-	(121)
Net Income (Loss)	$ 1,050	$ (63)	$ 91	$ 82	$ (71)	$ -	$ 1,089
Depreciation and AmortizationExpense	$ 1,256	$ 11	$ -	$ 32	$ 1	$ -	$ 1,300
Gross Property Additions	1,527	132	-	34	-	-	1,693
As of December 31, 2004							
Total Assets	$ 32,281	$ 1,801	$ 221 (c)	$ 1,345	$ 10,158	$ (11,143)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628
Investments in Equity Method Subsidiaries	-	33	-	117	-	-	150

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEPs investments in subsidiary companies.

(c) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

		Investments					
	Utility Operations	**Gas Operations**	**UK Operations**	**Other**	**All Other (a)**	**Reconciling Adjustments(b)**	**Consolidated**
2003				**(in millions)**			
Revenues from:							
External Customers	$ 10,869	$ 3,099	$ -	$ 699	$ -	$ -	$ 14,667
Other Operating Segments	146	27	-	94	11	(278)	-
Total Revenues	$ 11,015	$ 3,126	$ -	$ 793	$ 11	$ (278)	$ 14,667
Income (Loss) Before Discontinued Operations, Extraordinary Item and Cumulative Effect of AccountingChanges	$ 1,219	$ (290)	$ -	$ (278)	$ (129)	$ -	$ 522
Discontinued Operations, Net of Tax	-	(91)	(508)	(6)	-	-	(605)
Cumulative Effect of Accounting Changes, Net of Tax	236	(22)	(21)	-	-	-	193
Net Income (Loss)	$ 1,455	$ (403)	$ (529)	$ (284)	$ (129)	$ -	$ 110
Depreciation and AmortizationExpense	$ 1,250	$ 18	$ -	$ 39	$ -	$ -	$ 1,307
Gross Property Additions	1,323	25	-	10	-	-	1,358
As of December 31, 2003							
Total Assets	$ 30,829	$ 2,494	$ 1,662	$ 1,738	$ 13,604	$ (13,546)	$ 36,781
Assets Held for Sale	1,028	245	1,624	185	12	-	3,094

Investments in Equity Method Subsidiaries	-	36	-	156	-	-	192

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEPs investments in subsidiary companies.

		Investments					
	Utility Operations	**Gas Operations**	**UK Operations**	**Other**	**All Other(a)**	**Reconciling Adjustments**	**Consolidated**
2002				**(in millions)**			
Revenues from:							
External Customers	$ 10,446	$ 2,071	$ -	$ 910	$ -	$ -	$ 13,427
Other Operating Segments	45	212	-	149	-	(406)	-
Total Revenues	$ 10,491	$ 2,283	$ -	$ 1,059	$ -	$ (406)	$ 13,427
Income (Loss) Before Discontinued Operations, Extraordinary Item andCumulative Effect of AccountingChanges	$ 1,154	$ (99)	$ -	$ (522)	$ (48)	$ -	$ 485
Discontinued Operations, Net of Tax	-	8	(472)	(190)	-	-	(654)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	-	(350)	-	-	(350)
Net Income (Loss)	$ 1,154	$ (91)	$ (472)	$ (1,062)	$ (48)	$ -	$ (519)
Depreciation and AmortizationExpense	$ 1,276	$ 13	$ -	$ 67	$ -	$ -	$ 1,356
Gross Property Additions	1,517	47	-	25	96	-	1,685

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. However, energy markets are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contracts term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Contracts that have been designated as normal purchase or normal sale under SFAS 133 are not considered derivatives and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on if the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Consolidated Statements of Operations. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses in the Consolidated Statements of Operations depending on the relevant facts and circumstances.

We designate the hedging instrument, based on the exposure being hedged, as a fair value hedge, a cash flow hedge or a hedge of a net investment in a foreign operation. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statements of Operations during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) and subsequently reclassify it to Revenues in the Consolidated Statements of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change. For a hedge of a net investment in a foreign currency, we include the effective portion of the gain or loss in Accumulated Other Comprehensive Income as part of the cumulative translation adjustment. We recognize any ineffective portion of the gain or loss in Revenues immediately during the period of change.

Fair Value Hedging Strategies

We enter into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of the hedging activity was to protect the natural gas inventory against changes in fair value due to changes in the spot gas prices. The derivative contracts designated as fair value hedges of our natural gas inventory were MTM each month based upon changes in the NYMEX forward prices, whereas the natural gas inventory was MTM on a monthly basis based upon changes in the Gas Daily spot price at the end of the month. The differences between the indices used to MTM the natural gas inventory and the forward contracts designated as fair value hedges can result in volatility in our reported net income. However, over time gains or losses on the sale of the natural gas inventory will be offset by gains or losses on the fair value hedges, resulting in the realization of gross margin the Company anticipated at the time the transaction was structured. In the third quarter of 2004, the fair value hedges were de-designated, as a result the existing hedged inventory was held at the market price on the fair value hedge de-designation date with subsequent additions to inventory carried at cost. During the years ended December 31, 2004 and 2003, we recognized a pretax loss of approximately $(27.0) million and $(3.4) million, respectively, within revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. The interest rate forward and swap transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

We enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. We do not hedge all foreign currency exposure.

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. During 2004, we also entered into various forward starting interest rate swap contracts to manage the interest rate exposure on anticipated borrowings of fixed-rate debt through the second quarter of 2005. The anticipated debt offerings have a high probability of occurrence because the proceeds will be utilized to fund existing debt maturities as well as fund projected capital expenditures. We do not hedge all interest rate exposure. During 2004, we reclassified an immaterial amount to earnings because the original forecasted transaction did not occur within the originally specified time period.

We enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity and natural gas to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future sales and generation revenues. We do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity. During 2004, we classified an immaterial amount into earnings as a result of hedge ineffectiveness related to our cash flow hedging strategies.

We enter into natural gas futures contracts to protect against the reduction in value of forecasted cash flows resulting from spot purchases and sales of natural gas at Houston Ship Channel (HSC). We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future spot purchases and sales. We do not hedge all variable price risk exposure related to the forecasted spot purchase and sale of natural gas. The amount of hedges ineffectiveness was immaterial during 2004.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2004 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax (in millions)	Portion Expected to be Reclassified to Earnings during the Next 12 Months
Power and Gas	$ 88	$ (60)	$ 23	$ (26)
Interest Rate	1	(23)	(23)(a)	4
Foreign Currency	-	-	-	-
	$ 89	$ (83)	$ -	$ (22)

(a) Includes $3 million loss recorded in an equity investment.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2003 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax
		(in millions)	
Power and Gas	$ 21	$ (121)	$ (65)
Interest Rate	-	(7)	(9)(a)
Foreign Currency	-	(30)	(20)
	$ 21	$ (158)	$ (94)

(a) Includes $6 million loss recorded in an equity investment.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2004 and 2003, fourteen months and five years, respectively,are the maximum lengths of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows for forecasted transactions.

The following table represents the activity in Accumulated Comprehensive Other Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2004:

	Amount
	(in millions)
Beginning Balance, December 31, 2001	$ (3)
Changes in fair value	(56)
Reclasses from AOCI to net earnings	43
Balance at December 31, 2002	(16)
Changes in fair value	(79)
Reclasses from AOCI to net earnings	1
Balance at December 31, 2003	(94)
Changes in fair value	8
Reclasses from AOCI to net earnings	86
Ending Balance, December 31, 2004	$ -

Hedge of Net Investment in Foreign Operations

In 2002, we used foreign denominated fixed-rate debt to protect the value of our investments in foreign subsidiaries in the U.K. Realized gains and losses from these hedges are not included in the income statement, but are shown in the cumulative translation adjustment account included in Accumulated Other Comprehensive Income (Loss).

During 2002, we recognized $64 million of net losses, included in the cumulative translation adjustment, related to the foreign denominated fixed-rate debt.

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2004 and 2003 are summarized in the following tables.

	2004		2003	
	Book Value	Fair Value	Book Value	Fair Value
		(in millions)		
Long-term Debt	$ 12,287	$ 12,813	$ 14,101	$ 14,621
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	66	67	76	76

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments which are classified as available for sale for decommissioning and SNF disposal, reported in Spent Nuclear Fuel and Decommissioning Trusts and Assets of Discontinued Operations and Held for Sale on our Consolidated Balance Sheets, are recorded at market value in accordance with SFAS 115, Accounting for Certain Investments in Debt and Equity Securities. At December 31, 2004 and 2003, the fair values of the trust investments were $1.2 billion and $1.1 billion, respectively, and had a cost basis of $1.0 billion and $1.0 billion, respectively. The change in market value in 2004, 2003 and 2002 was a net unrealized gain of $41 million and $53 million and a net unrealized loss of $33 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary item and cumulative effect of accounting changes as reported are as follows:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Federal:			
Current	$ 262	$ 297	$ 307
Deferred	263	34	(60)
Total	525	331	247
State and Local:			
Current	49	19	32
Deferred	(3)	1	28
Total	46	20	60
International:			

Current	1	7	8
Deferred	-	-	-
Total	1	7	8
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes	$ 572	$ 358	$ 315

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in millions)	
Net Income (Loss)	$ 1,089	$ 110	$ (519)
Discontinued Operations (net of income tax of $75 million, $(312)million and $(174) millionin 2004, 2003 and 2002, respectively)	(83)	605	654
Extraordinary Loss on Texas Stranded Cost Recovery, (net of income tax of $(64) million in 2004)	121	-	-
Cumulative Effect of Accounting Changes (net of income tax of $138 million and $0 in 2003 and 2002,respectively)	-	(193)	350
Preferred Stock Dividends	6	9	11
Income Before Preferred Stock Dividends of Subsidiaries	1,133	531	496
Income Taxes Before Discontinued Operations, Extraordinary Itemand Cumulative Effect of Accounting Changes	572	358	315
Pretax Income	$ 1,705	$ 889	$ 811
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 597	$ 311	$ 284
Increase (Decrease) in Income Taxes resulting from the followingItems:			
Depreciation	36	34	32
Asset Impairments and Investment Value Losses	-	23	4
Investment Tax Credits (net)	(29)	(33)	(35)
Tax Effects of International Operations	1	8	27
Energy Production Credits	(16)	(15)	(14)
State Income Taxes	30	13	39
Other	(47)	17	(22)
Total Income Taxes as Reported Before DiscontinuedOperations, Extraordinary Item and Cumulative Effect ofAccounting Changes	$ 572	$ 358	$ 315
Effective Income Tax Rate	33.5 %	40.3 %	38.8 %

The following table shows our elements of the net deferred tax liability and the significant temporary differences.

As of December 31,

	2004	2003
	(in millions)	
Deferred Tax Assets	$ 2,280	$ 3,354
Deferred Tax Liabilities	(7,099)	(7,311)
Net Deferred Tax Liabilities	(4,819)	(3,957)
Property Related Temporary Differences	$ (3,273)	$ (2,850)
Amounts Due From Customers For Future Federal Income Taxes	(184)	(180)
Deferred State Income Taxes	(452)	(416)
Transition Regulatory Assets	(211)	(254)
Securitized Transition Assets	(258)	(281)
Regulatory Assets	(578)	(195)
Deferred Income Taxes on Other Comprehensive Loss	186	306
All Other (net)	(49)	(87)
Net Deferred Tax Liabilities	$ (4,819)	$ (3,957)

The IRS and other taxing authorities routinely examine our tax returns. Management believes that we have filed tax returns with positions that may be challenged by these tax authorities. These positions relate to, among others, the federal treatment of taxes paid to foreign taxing authorities (the most significant of which is the federal treatment of the U.K. Windfall Profits Tax), the timing and amount of deductions and the tax treatment related to acquisitions and divestitures. We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agents Reports from the IRS for the years 1991 through 1999, and have filed protests contesting certain proposed adjustments. CSW, which was a separate consolidated group prior to its merger with AEP, is currently being audited for the years 1997 through the date of merger in June 2000. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in managements opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2004, the Company has total provisions for uncertain tax positions of approximately $144 million. In addition, the Company accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP Systems current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

16. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Lease Payments on Operating Leases	$ 317	$ 344	$ 359
Amortization of Capital Leases	54	64	65

Interest on Capital Leases	11	9	14
Total Lease Rental Costs	$ 382	$ 417	$ 438

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31,	
	2004	2003
	(in millions)	
Property, Plant and Equipment Under Capital Leases:		
Production	$ 91	$ 37
Distribution	15	15
Other	323	470
Total Property, Plant and Equipment	429	522
Accumulated Amortization	186	218
Net Property, Plant and Equipment Under Capital Leases	$ 243	$ 304
Obligations Under Capital Leases:		
Noncurrent Liability	$ 190	$ 131
Liability Due Within One Year	53	51
Total Obligations under Capital Leases	$ 243	$ 182

Future minimum lease payments consisted of the following at December 31, 2004:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2005	$ 64	$ 291
2006	55	259
2007	42	246
2008	30	231
2009	21	221
Later Years	92	2,181
Total Future Minimum Lease Payments	$ 304	$ 3,429
Less Estimated Interest Element	61	
Estimated Present Value of Future Minimum Lease Payments	$ 243	

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and previously leased it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($470 million). Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for as an operating lease. For 2002 and the first half of 2003, operating lease payments related to the Gavin Scrubber were recorded as operating lease expense by OPCo. After July 1, 2003, OPCo records the depreciation, interest and other operating expenses of JMG and eliminates JMGs rental revenues against OPCos operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of the requirement to consolidate JMG and there was no change in net income due to the consolidation of JMG. The debt obligations of JMG are now included in long-term debt as Notes Payable and Installment Purchase Contracts and are excluded from the above table of future minimum lease payments.

At any time during the obligation, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year term is noncancelable. At the end of the initial term, OPCo can renew the obligation, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In the case of a sale at less than the adjusted acquisition cost, OPCo is required pay the difference to JMG.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company as of December 31, 2004 are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payments included in the future minimum lease payments schedule earlier in this note. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2004, the maximum potential loss was approximately $32 million ($21 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other rail car lease arrangements that do not utilize this type of structure.

17. <u>FINANCING ACTIVITIES</u>

Dividend Restrictions

Under PUHCA, AEP and its public utility subsidiaries can only pay dividends out of retained or current earnings.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Balance Sheet. The investment in the trust is reported as Other within Other Noncurrent Assets while the Junior Subordinated Debentures are reported as Notes Payable to Trust within Long-term Debt.

In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are due October 1, 2043. Junior Subordinated Debentures were retired in the second quarter of 2004 for PSO and in the third quarter of 2004 for TCC. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2004 and 2003:

Business Trust	**Security**	**Units Issued/ Outstanding at 12/31/04**	**Amount in Other at 12/31/04** (a)	**Amount in Notes Payable to Trust at 12/31/04** (b)	**Amount in Other at 12/31/03** (a)	**Amount in Notes Payable to Trust at 12/31/03** (b)	**Description of Underlying Debentures of Registrant**
				(in millions)			
CPL Capital I	8.00%, Series A	-	$ -	$ -	$ 5	$ 141	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	-	-	-	2	77	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	3	113	SWEPCo, $113 million, 5.25% 5-year fixed rate period, Series B
Total		110,000	$ 3	$ 113	$ 10	$ 331	

(a) Amounts are in Other within Other Noncurrent Assets.

(b) Amounts are in Notes Payable to Trust within Long-term Debt.

Each of the business trusts is treated as a nonconsolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under the subordinated debentures, the parent company has also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that held the assets of HPL and LIG. Caddis was capitalized with $2 million cash from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a noncontrolling preferred member interest. As managing member, SubOne consolidated Caddis. Steelhead was an unconsolidated special purpose entity whose investors had no relationship to us or any of our subsidiaries. The money invested in Caddis by Steelhead was loaned to SubOne.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis. As a result, a note payable ($533 million) to Caddis was reported as a component of Long-term Debt on July 1, 2003, the balance of which was $0 and $525 million on December 31, 2004 and December 31, 2003, respectively. Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

Equity Units

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note.

The forward purchase contracts obligate the holders to purchase shares of AEP common stock on August 16, 2005. The purchase price per equity unit is $50. The number of shares to be purchased under the forward purchase contract will be determined under a formula based upon the average closing price of AEP common stock near the stock purchase date. Holders may satisfy their obligation to purchase AEP common stock under the forward purchase contracts by allowing the senior notes to be remarketed or by continuing to hold the senior notes and using other resources as consideration for the purchase of stock. If holders remarket their notes, the proceeds from the remarketing will be used to purchase a portfolio of U.S. treasury securities that the holders will pledge to AEP in order to meet their obligations under the forward purchase contracts.

The senior notes have a principal amount of $50 each and mature on August 16, 2007. The senior notes are the collateral that secures the holders requirement to purchase common stock under the forward purchase contracts.

AEP is making quarterly interest payments on the senior notes at an initial annual rate of 5.75%. The interest rate can be reset through a remarketing, which is initially scheduled for May 2005. AEP makes contract adjustment payments to the purchaser at the annual rate of 3.50% on the forward purchase contracts. The present value of the contract adjustment payments was recorded as a $31 million liability in Equity Unit Senior Notes offset by a charge to Paid-in Capital in June 2002. Interest payments on the senior notes are reported as interest expense. Accretion of the contract adjustment payment liability is reported as interest expense.

AEP applies the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contract are used to repurchase outstanding shares.

Lines of Credit - AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2004, we had credit facilities totaling $2.8 billion to support our commercial paper program. At December 31, 2004, we had $23 million in outstanding commercial paper related to JMG Funding. This commercial paper is specifically associated with the Gavin Scrubber as identified in the Gavin Scrubber Financing Arrangement section of Note 16 and is backed by a separate credit facility. This commercial paper does not reduce our available liquidity. As of December 31, 2004, our commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $661 million in June 2004 and the weighted average interest rate of commercial paper outstanding during the year was 1.81%. On February 10, 2003, Moodys Investor Services downgraded our short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poors Rating Services reaffirmed our A-2 short-term rating for commercial paper. On August 2, 2004, Moodys Investor Services placed our ratings on positive outlook.

Outstanding Short-term Debt consisted of:

December 31,

	2004	2003
	(in millions)	
Balance Outstanding		
Notes Payable	$ -	$ 18
Commercial Paper - AEP	-	282
Commercial Paper - JMG	23	26
Total	$ 23	$ 326

Sale of Receivables - AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credits balance sheet and allowing AEP Credit to repay any debt obligations. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. We continue to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies receivables, and accelerate its cash collections.

During 2004, AEP Credit renewed its sale of receivables agreement which had expired on August 25, 2004. As a result of the renewal, AEP Credits sale of receivables agreement will now expire on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCos accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31,	
	2004	2003
	(in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,163	$ 5,221
Accounts Receivable Retained Interest and Pledged asCollateral Less Uncollectible Accounts	80	124
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	7
Average Variable Discount Rate	1.50 %	1.33 %
Retained Interest if 10% Adverse Change in Uncollectible Accounts	78	122
Retained Interest if 20% Adverse Change in Uncollectible Accounts	76	121

Historical loss and delinquency amount for the AEP Systems customer accounts receivable managed portfolio is as follows:

	Face Value	
	Year Ended December 31,	
	2004	2003
	(in millions)	
Customer Accounts Receivable Retained	$ 930	$ 1,155
Accrued Unbilled Revenues Retained	592	596
Miscellaneous Accounts Receivable Retained	79	83
Allowance for Uncollectible Accounts Retained	(77)	(124)
Total Net Balance Sheet Accounts Receivable	1,524	1,710
Customer Accounts Receivable Securitized (Affiliate)	435	385
Total Accounts Receivable Managed	$ 1,959	$ 2,095
Net Uncollectible Accounts Written Off	$ 86	$ 39

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $25 million and $30 million at December 31, 2004 and 2003, respectively.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

	2004 Quarterly Periods Ended			
(In Millions - Except Per Share Amounts)	March 31	June 30	September 30	December 31
Revenues	$ 3,364	$ 3,408	$ 3,780	$ 3,505
Operating Income	633	413	639	306
Income Before Discontinued Operations and Extraordinary Item	289	151	412	275
Net Income	282	100	530	177
Earnings per Share Before Discontinued Operations and Extraordinary Item (a)	0.73	0.38	1.04	0.69
Earnings per Share	0.71	0.25	1.34	0.45

	2003 Quarterly Periods Ended			
(In Millions - Except Per Share Amounts)	March 31	June 30	September 30	December 31
Revenues	$ 3,806	$ 3,491	$ 3,966	$ 3,404
Operating Income (Loss)	651	434	760	(91)
Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes	293	177	307	(255)
Net Income (Loss)	440	175	257	(762)
Earnings (Loss) per Share Before Discontinued Operations and Cumulative Effect of Accounting Changes (b)	0.82	0.45	0.78	(0.65)

Earnings (Loss) per Share (c)	1.24	0.44	0.65	(1.93)

(a) Amounts for 2004 do not add to $2.85 earnings per share before Discontinued Operations and Extraordinary Item due to rounding.

(b) Amounts for 2003 do not add to $1.35 earnings per share before Discontinued Operations, Extraordinary Item and Cumulative Effect of Accounting Changes due to rounding and the dilutive effect of shares issued in 2003.
(c) Amounts for 2003 do not add to $0.29 earnings per share due to rounding and the dilutive effect of shares issued in 2003.

Income (Loss) Before Discontinued Operations and Cumulative Effect of Accounting Changes for the fourth quarter of 2003 ($255 million loss) was significantly lower than the previous three quarters due to asset impairments, investment value losses and other related charges. These pretax writedowns ($650 million in the fourth quarter of 2003) were made to reflect impairments and discontinued operations as discussed in Note 10.

19. SUBSEQUENT EVENT

On January 27, 2005, we sold a 98% controlling interest in HPL, 30 BCF of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We are retaining a 2% ownership interest in HPL and will provide certain transitional administrative services to the buyer. The determination of the amount of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the Bank of America (BOA) dispute. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA (see Enron Bankruptcy - Right to use of cushion gas agreements section of Note 7).

We also have a put option expiring in 2006, which allows us to sell our remaining 2% interest to the buyer for approximately $16 million.

HPL is classified as held and used instead of held for sale as of December 31, 2004 due to the magnitude and uncertainty surrounding the BOA dispute and what level of indemnification a potential buyer might require. In addition, the indicative bid and our Board of Directors approval to sell HPL were received subsequent to December 31, 2004.

AEP GENERATING COMPANY

AEP GENERATING COMPANY

SELECTED FINANCIAL DATA

(in thousands)

	2004		2003	2002	2001	2000
STATEMENTS OF INCOME DATA						
Operating Revenues	$ 241,788		$ 233,165	$ 213,281	$ 227,548	$ 228,516
Operating Income	6,904		7,174	6,129	6,977	8,424
Interest Charges	2,446		2,550	2,258	2,586	3,869
Net Income	7,842		7,964	7,552	7,875	7,984
BALANCE SHEETS DATA						
Electric Utility Plant	$ 689,577		$ 674,055	$ 652,213	$ 648,254	$ 642,302
Accumulated Depreciation and Amortization	368,484		351,062	330,187	310,804	290,858
Net Electric Utility Plant	$ 321,093		$ 322,993	$ 322,026	$ 337,450	$ 351,444
TOTAL ASSETS	$ 376,393		$ 380,045	$ 377,716	$ 387,688	$ 399,310
Common Shareholder's Equity	48,671		45,875	42,597	38,195	34,156
Long-term Debt (a)	44,820		44,811	44,802	44,793	44,808
Obligations Under Capital Leases (a)	12,474	(b)	269	501	311	591

(a) Including portion due within one year.

(b) Increased primarily due to a new coal transportation lease. See Note 15.

AEP GENERATING COMPANY

MANAGEMENTS NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEGCo, co-owner of the Rockport Plant, is engaged in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and the other co-owner of the Rockport Plant.

Operating revenues are derived from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. Under the terms of its unit power agreement, I&M agreed to purchase all of our Rockport energy and capacity unless it is sold to other utilities or affiliates. I&M assigned 30% of its rights to energy and capacity to KPCo. In December 2004, KPSC and the FERC approved a Stipulation and Settlement Agreement which, among other things, extends the unit power agreement with KPCo until December 7, 2022.

The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, AEGCo accumulates all expenses monthly and prepares bills for its affiliates. In the month the expenses are incurred, AEGCo recognizes the billing revenues and establishes a receivable from the affiliated companies. Costs of operating the plant are divided between the co-owners.

Results of Operations

Net Income decreased $0.1 million for 2004 compared with 2003. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant calculated and adjusted monthly.

2004 Compared to 2003

Operating Income

Operating Income decreased $0.3 million from the prior year. The largest variances related to:

A $3.2 million increase in Fuel for Electric Generation expense primarily due to an 8.7% increase in average fuel costs per KWH generated.

A $1.9 million increase in Income Taxes. See Income Taxes section below for further discussion.
A $1.8 million increase in Maintenance expenses as a result of increased planned boiler inspections and forced repairs.
A $0.8 million increase in Taxes Other Than Income Taxes as a result of Indiana property tax reappraisals.
A $0.7 million increase in Depreciation and Amortization reflecting an increase in assets being depreciated.
A $0.5 million increase in Other Operation expenses reflecting increased employee pension and benefit costs.

The above expense increases were recovered per the terms of the unit power agreement by:

An $8.6 million increase in Operating Revenues as a result of increased recoverable expenses.

Income Taxes

The effective tax rates for 2004 and 2003 were (1.5)% and (31.5)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences, and state income taxes. The increase in the effective tax rate is primarily due to higher state income taxes and changes in flow-through temporary differences.

Off-Balance Sheet Arrangements

Rockport Plant Unit 2

In 1989, AEGCo and I&M entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote (see Note 15). The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Our contractual obligations include amounts reported on the Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payments due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Advances from Affiliates (a)	$ 26.9	$ -	$ -	$ -	$ 26.9
Capital Lease Obligations (b)	1.0	2.0	1.9	18.0	22.9
Noncancelable Operating Leases (b)	74.0	147.9	147.9	960.2	1,330.0
Total	$ 101.9	$ 149.9	$ 149.8	$ 978.2	$ 1,379.8

(a) Represents short-term borrowings from the Utility Money Pool.

(b) See Note 15. The lease of the Plant is reported in Noncancelable Operating Leases.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, income taxes, and the impact of new accounting pronouncements.

AEP GENERATING COMPANY

STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES	$ 241,788	$ 233,165	$ 213,281
OPERATING EXPENSES			
Fuel for Electric Generation	112,470	109,238	89,105
Rent - Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	10,866	10,399	12,924
Maintenance	12,152	10,346	9,418
Depreciation and Amortization	23,390	22,686	22,560
Taxes Other Than Income Taxes	4,181	3,396	3,281
Income Taxes	3,542	1,643	1,581
TOTAL	234,884	225,991	207,152
OPERATING INCOME	6,904	7,174	6,129
Nonoperating Income	43	151	344
Nonoperating Expenses	317	361	199
Nonoperating Income Tax Credits	3,658	3,550	3,536
Interest Charges	2,446	2,550	2,258
NET INCOME	$ 7,842	$ 7,964	$ 7,552

STATEMENTS OF RETAINED EARNINGS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
BALANCE AT BEGINNING OF PERIOD	$ 21,441	$ 18,163	$ 13,761
Net Income	7,842	7,964	7,552
Cash Dividends Declared	5,046	4,686	3,150
BALANCE AT END OF PERIOD	$ 24,237	$ 21,441	$ 18,163

The common stock of AEGCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY

BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 681,254	$ 645,251
General	3,739	4,063
Construction Work in Progress	7,729	24,741
Total	692,722	674,055
Accumulated Depreciation and Amortization	368,484	351,062
TOTAL - NET	324,238	322,993
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	23,078	24,748
Fuel	16,404	20,139
Materials and Supplies	5,962	5,419
TOTAL	45,444	50,306
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,496	4,733
Asset Retirement Obligations	1,117	928
Deferred Property Taxes	557	502
Other Deferred Charges	422	464
TOTAL	6,592	6,627
TOTAL ASSETS	$ 376,393	$ 380,045

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - $1,000 Par Value Per Share:		
Authorized and Outstanding - 1,000 Shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	23,434
Retained Earnings	24,237	21,441
Total Common Shareholders Equity	48,671	45,875
Long-term Debt	44,820	44,811
TOTAL	93,491	90,686
CURRENT LIABILITIES		
Advances from Affiliates	26,915	36,892
Accounts Payable:		
General	443	498
Affiliated Companies	17,905	15,911
Taxes Accrued	8,806	6,070
Interest Accrued	911	911
Obligations Under Capital Leases	210	87
Rent Accrued - Rockport Plant Unit 2	4,963	4,963
Other	73	-
TOTAL	60,226	65,332
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	24,762	24,329
Regulatory Liabilities:		
Asset Removal Costs	25,428	27,822
Deferred Investment Tax Credits	46,250	49,589
SFAS 109 Regulatory Liability, Net	12,852	15,505
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	99,904	105,475
Obligations Under Capital Leases	12,264	182
Asset Retirement Obligations	1,216	1,125
TOTAL	222,676	224,027
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 376,393	$ 380,045

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 7,842	$ 7,964	$ 7,552
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	23,390	22,686	22,560
Deferred Income Taxes	(2,219)	(5,838)	(5,028)
Deferred Investment Tax Credits	(3,339)	(3,354)	(3,361)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Changes in Other Noncurrent Assets	3,455	3,486	(5,455)
Changes in Other Noncurrent Liabilities	(2,511)	1,120	102
Changes in Components of Working Capital:			
Accounts Receivable	1,670	(6,294)	4,037
Fuel, Materials and Supplies	3,192	(385)	(5,450)
Accounts Payable	1,939	476	6,697
Taxes Accrued	2,736	3,743	(2,450)
Other Current Assets	-	-	244
Other Current Liabilities	196	(113)	(2,397)
Net Cash Flows From Operating Activities	30,780	17,920	11,480
INVESTING ACTIVITIES			
Construction Expenditures	(15,757)	(22,197)	(5,298)
Change in Other Cash Deposits, Net	-	-	983
Proceeds from Sale of Assets	-	105	-
Net Cash Flows Used For Investing Activities	(15,757)	(22,092)	(4,315)
FINANCING ACTIVITIES			
Change in Advances to/from Affiliates, Net	(9,977)	8,858	(4,015)
Dividends Paid	(5,046)	(4,686)	(3,150)
Net Cash Flows From (Used For) Financing Activities	(15,023)	4,172	(7,165)
Net Change in Cash and Cash Equivalents	-	-	-
Cash and Cash Equivalents at Beginning of Period	-	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -	$ -

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $2,179,000, $2,283,000 and $2,019,000 and for income taxes was $542,000, $6,483,000 and $7,884,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $12,297,000.

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY

SCHEDULE OF LONG-TERM DEBT

December 31, 2004 and 2003

(in thousands)

	Series	Due Date	2004	2003
LONG-TERM DEBT -				
Installment Purchase Contracts - City of Rockport (a)				
	Series	**Due Date**		
	1995 A	2025 (b)	$ 22,500	$ 22,500
	1995 B	2025 (b)	22,500	22,500
Unamortized Discount			(180)	(189)
TOTAL LONG-TERM DEBT			$ 44,820	$ 44,811

(a) We entered into installment purchase contracts in connection with the issuance of pollution control revenue bonds by the City of Rockport, Indiana. The terms of the installment purchase contracts require our payment of amounts sufficient to enable the payment of interest and principal on the related pollution control revenue bonds issued to refinance the construction costs of pollution control facilities at the Rockport Plant. The bonds due in 2025 are subject to mandatory tender for purchase in July 2006. Consequently, the bonds have been classified for repayment purposes in 2006.

(b) These series have an adjustable interest rate that we can designate as a daily, weekly, commercial paper or term rate. In July 2001, we selected a term rate of 4.05% for five years ending July 12, 2006.

None of our long-term debt obligations have been guaranteed or secured by AEP or any of our affiliates.

See Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to AEGCos financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to AEGCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of

AEP Generating Company:

We have audited the accompanying balance sheets of AEP Generating Company as of December 31, 2004 and 2003, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,175,266	$ 1,747,511	$ 1,690,493	$ 1,738,837	$ 1,770,402
Operating Income	196,019	321,540	393,733	295,731	307,098
Carrying Costs on Stranded Cost Recovery (a)	301,644	-	-	-	-
Interest Charges	123,785	133,812	125,871	116,268	124,766
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	294,656	217,547	275,941	182,278	189,567
Extraordinary Loss on Stranded Cost Recovery,Netof Tax (a)	(120,534)	-	-	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	122	-	-	-
Net Income	174,122	217,669	275,941	182,278	189,567
BALANCE SHEETS DATA					
Electric Utility Plant	$ 2,492,798	$ 2,425,038	$ 2,334,794	$ 2,231,287	$ 2,097,497
Accumulated Depreciation and Amortization	725,225	695,359	662,345	616,526	570,522
Net Electric Utility Plant	$ 1,767,573	$ 1,729,679	$ 1,672,449	$ 1,614,761	$ 1,526,975
Total Assets	$ 5,695,790	$ 5,854,429	$ 5,515,723	$ 4,989,381	$ 5,556,275
Common Shareholder's Equity	1,268,643	1,209,049	1,101,134	1,400,100	1,366,123
Cumulative Preferred Stock Not Subject toMandatory Redemption	5,940	5,940	5,942	5,952	5,951
Trust Preferred Securities (b)	-	-	136,250	136,250	148,500
Long-term Debt (c)	1,907,294	2,291,625	1,438,565	1,253,768	1,454,559
Obligations Under Capital Leases (c)	880	1,043	-	-	-

(a) See Carrying Costs on Net True-up Regulatory Assets and Net Stranded Generation Costs sections of Note 6.

(b) See Trust Preferred Securities section of Note 16.
(c) Including portion due within one year.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS

TCC is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power. We consolidate AEP Texas Central Transition Funding LLC, our wholly-owned subsidiary. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pools sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, a municipality, rural electric cooperatives and REPs in Texas.

Power pool members are compensated for energy delivered to other members based upon the delivering members incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

Net Income decreased $44 million for 2004. The major factors driving the decline are decreased revenues associated with establishing regulatory assets in Texas in 2003 and the extraordinary item related to stranded cost in 2004, offset in part in 2004 by the cessation of depreciation on plants held for sale and the capitalization of carrying costs on recoverable stranded costs. The sale of several of our generation plants in July 2004 affected numerous line items on the income statement and reduced the amount of margins recognized from the generation operations.

Operating Income

Operating Income decreased $126 million primarily due to:

A $215 million decrease in revenues associated with establishing regulatory assets in Texas in 2003 (see Texas Restructuring and Wholesale Capacity Auction True-up section of Note 6).

A $214 million decrease in off-system sales, including those to REPs, primarily due to lower KWH sales of 36%. The decrease in KWH sales is due to customer choice in Texas and the sale of certain generation plants.

A $127 million decrease in Reliability Must Run (RMR) revenues from ERCOT, which includes both a fuel recovery decrease of $108 million and a fixed cost component decrease of $19 million due to TCC no longer having RMR plants. In 2004, RMR revenues totaled $115 million of which $16 million was for reimbursement of fixed costs.

A $24 million decrease in revenues from ERCOT for various services including balancing energy and prior year adjustments made by ERCOT.

A $13 million decrease in margins from risk management activities.

A $12 million increase in Other Operation expenses primarily due to a $10 million increase of ERCOT-related transmission expense and affiliated ancillary services resulting from revised data received from ERCOT for the years 2001-2003; a $4 million increase in distribution related expense; and a $6 million increase in general and administrative expenses; offset by a $9 million decrease in production expenses due to the sale of certain generation plants.

A $10 million decrease in Qualified Scheduling Entity (QSE) fees primarily due to one REP not using TCC as their QSE in 2004.

The decrease in Operating Income was partially offset by:

A $303 million net decrease in fuel and purchased power expenses. KWHs purchased decreased 51% while the per unit cost increased 20%. Per unit generation costs decreased 29% and KWHs generated decreased 21% due to the sale of certain generation plants and the fact that lower cost nuclear fuel generation became a larger part of the generation mix after the sale.

A $75 million decrease in Depreciation and Amortization expenses primarily due to the cessation of depreciation on plants sold and plants classified as held for sale (see Dispositions and Assets Held for Sale sections of Note 10).

A $71 million decrease in Income Taxes. See Income Taxes section below for further discussion.

A $21 million increase in revenues due to a decrease in provisions for rate refunds primarily due to fuel reconciliation issues (see TCC Fuel Reconciliation section of Note 4).

A $15 million increase in transmission revenue primarily due to affiliated open access transmission tariff (including an $8 million true-up for prior years recorded in 2004 resulting from revised data received from ERCOT for the years 2001-2003) and ancillary services.

An $8 million decrease in Maintenance expenses primarily due to the sale of certain generation plants.

Other Impacts on Earnings

We recorded in income a carrying cost of $302 million on stranded cost recovery (see Carrying Costs on Net True-up Regulatory Assets section of Note 6).

Nonoperating income decreased $8 million primarily due to a decrease in risk management activities.

Interest Charges decreased $10 million primarily due to the defeasance of $112 million of First Mortgage Bonds, and the resultant deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust, and other financing activities.

Income Taxes

The effective tax rates for 2004 and 2003 were 31.4% and 32.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35.0% is due to permanent differences, amortization of investment tax credits, consolidated tax savings, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Extraordinary Loss on Stranded Cost Recovery, Net of Tax

See Texas Restructuring and Net Stranded Generation Costs sections of Note 6 for a discussion of net adjustments of stranded costs recorded in the fourth quarter of 2004.

2003 Compared to 2002

Net Income decreased $58 million for 2003. The decrease is primarily due to an increased provision for refunds of $85 million ($55 million after tax) and a decrease in the recognition of noncash earnings related to legislatively-mandated capacity auctions and regulatory assets established in Texas of $29 million net of tax. Additionally, income from transactions with ERCOT increased significantly due mainly to Texas Restructuring Legislation.

Since REPs are the electricity suppliers to retail customers in the ERCOT area, we sell our generation to the REPs and other market participants and provide transmission and distribution services to retail customers of the REPs in our service territory. As a result of the provision of retail electric service by REPs, effective January 1, 2002, we no longer supply electricity directly to retail customers. The implementation of REPs as suppliers to retail customers has caused a shift in our sales as further described below.

In December 2002, AEP sold Mutual Energy CPL to an unrelated third party, who assumed the obligations of the affiliated REP including the provision of price-to-beat rates under the Texas Restructuring Legislation. Prior to the sale, during 2002, sales to Mutual Energy CPL were classified as Sales to AEP Affiliates. Subsequent to the sale, energy transactions and delivery charges with Mutual Energy CPL are classified as Electric Generation, Transmission and Distribution.

Operating Income

Operating Income decreased $72 million primarily due to:

A $197 million net increase in fuel and purchased power expenses to replace portions of the energy from the non-RMR mothballed plants and the unscheduled forced outage at the STP nuclear unit. KWHs purchased increased 47% while the cost increased 54%. Although the KWHs generated decreased, fuel costs increased 16% due to higher per unit costs attributable mostly to natural gas.
An $85 million increase in provisions for rate refunds primarily due to 2003 Texas fuel issues (see TCC Fuel Reconciliation section of Note 4).
A $59 million decrease in revenue due to the 2002 interchange cost reconstruction adjustments with an offsetting $51 million decrease in purchased power.
A $44 million decrease in revenues associated with establishing regulatory assets in Texas in 2003 (see Texas Restructuring section of Note 6). These revenues did not continue after 2003.
A $24 million decrease in retail revenues driven by a 9% decrease in cooling degree-days offset by a slight increase in heating degree days. Average price per KWH decreased 2%.
An $8 million increase in Maintenance expense primarily due to the STP Unit 2 forced outage in the first quarter of 2003, and the STP Unit 1 scheduled refueling outage and forced outage in the second and third quarters of 2003.
A $7 million decrease in revenues from ERCOT for various services, including balancing energy.
A $7 million decrease in off-system sales, including those to REPs, primarily due to a decrease in the overall average price per KWH and higher KWH sales of 2%.

The decrease in Operating Income was partially offset by:

A $214 million increase in RMR revenues from ERCOT which include both fuel recovery and a fixed cost component of $35 million (see Texas Plants in Note 10 for discussion of RMR facilities).

A $41 million decrease in Income Taxes. See Income Taxes section below for further discussion.
A $31 million increase in margins resulting from risk management activities.

- A $25 million increase in other operating revenue comprised primarily of miscellaneous service revenue and fees as a result of the Texas Restructuring Legislation.
- A $24 million decrease in Depreciation and Amortization expense primarily due to decreases resulting from ARO of $16 million (see Asset Retirement Obligations in Note 2) and reduced depreciable plant by $6 million due to the mothballing of certain generating units in 2002.
- A $7 million decrease in Other Operation expense primarily due to lower distribution and customer related expenses in 2003, offset in part by $16 million of accretion expense associated with the implementation of SFAS 143, as well as increased costs of $6 million related to 2003 ERCOT transmission charges.
- A $3 million decrease in Taxes Other Than Income Taxes primarily due to reduced gross receipt taxes as a result of the sale of the Texas REPs, partially offset by higher property taxes.

Other Impacts on Earnings

Nonoperating Income increased $1 million. While 2003 gains from risk management activities increased $33 million, they are almost totally offset by lower 2003 revenues of $33 million from third party nonutility energy related construction projects.

Nonoperating Expense decreased $25 million primarily due to lower nonutility expenses associated with energy related construction projects for third parties.

Interest Charges increased $8 million primarily due to the replacement of lower cost short-term floating rate debt with longer-term higher cost fixed rate debt.

Income Taxes

The effective tax rates for 2003 and 2002 were 32.6% and 34.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35.0% is due to permanent differences, amortization of investment tax credits, consolidated tax savings, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Change

This amount represents the one-time after tax effect of the application of EITF 02-3 (see Accounting for Risk Management Contracts in Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moodys	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the year ended December 31, 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 760	$ 807	$ 10,610
Cash flows from (used for):			
Operating activities	274,110	357,378	128,109
Investing activities	216,561	(104,980)	(216,432)
Financing activities	(491,431)	(252,445)	78,520
Net decrease in cash and cash equivalents	(760)	(47)	(9,803)
Cash and cash equivalents at end of period	$ -	$ 760	$ 807

Operating Activities

Our net cash flows from operating activities were $274 million in 2004. We produced income of $174 million during the period and noncash items of $123 million for Depreciation and Amortization, $121 million for an Extraordinary Loss on Stranded Cost Recovery and $(302) million for Carrying Costs on Stranded Cost Recovery. See Results of Operations for discussions of these items. The change in Other Noncurrent Assets and other liabilities are primarily due to additional pension plan funding during the current year. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $117 million change in Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extension is filed.

Our net cash flows from operating activities were $357 million in 2003. We produced income of $218 million during the period and noncash items of $198 million for Depreciation and Amortization (see Results of Operations) and $(218) million for Wholesale Capacity Auction True-up (see Texas Restructuring and Wholesale Capacity Auction True-up in Note 6). The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are a $56 million change in Accounts Payable primarily due to increased payables related to gas purchases and a $42 million change in Taxes Accrued as a result of taxes that were accrued during 2003 in excess of the amount remitted to the government.

Our net cash flows from operating activities were $128 million in 2002. We produced income of $276 million during the period and noncash items of $222 million for Depreciation and Amortization (see Results of Operations), $114 million for Deferred Income Taxes and $(262) million for Wholesale Capacity Auction True-up (see Texas Restructuring and Wholesale Capacity Auction True-up section of Note 6). Deferred Income Taxes of $114 million were primarily due to the recording of deferred taxes related to the Wholesale Capacity Auction True-up. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $(217) million change in Accounts Receivable, Net primarily due to increased receivables related to the changes associated with the Texas Restructuring Legislation and an adjustment to the interchange cost reconstruction system.

Investing Activities

Our net cash flows from investing activities in 2004 were $217 million primarily due to $430 million in proceeds from the sale of several of our generation plants offset in part by $121 million of construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Our net cash flows used for investing activities in 2003 were $105 million primarily due to construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Our net cash flows used for investing activities in 2002 were $216 million primarily due to construction expenditures.

Financing Activities

Our net cash flows used for financing activities in 2004 were $491 million primarily due to the retirement of long-term debt and payment of dividends on common stock mainly with funds received from the sale of generation plants.

Our net cash flows used for financing activities in 2003 were $252 million primarily due to replacing both short and long-term debt with proceeds from new borrowings.

Our net cash flows from financing activities in 2002 were $79 million primarily due to the issuance of short-term debt. This issuance was partially offset by the retirement of common stock and decreased borrowing from the Utility Money Pool resulting from TCC Transition Funding new debt.

In February 2005, we reissued $162 million Matagorda County Navigation District Installment Purchase Contracts due May 1, 2030 that were put to us in November 2004. These bonds had not been retired as we intended to reissue the bonds at a later date. The original installment purchase contracts were mandatory one-year put bonds with fixed rates of 2.15% for Series A and 2.35% for Series B at the time of the put. The reissued contracts bear interest at 35-day auction rates.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payments Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ 365.7	$ 205.6	$ 122.3	$ 1,216.6	$ 1,910.2
Advances from Affiliates (b)	0.2	-	-	-	0.2
Capital Lease Obligations (c)	0.5	0.4	0.1	-	1.0
Noncancelable Operating Leases (c)	5.8	7.6	5.1	6.2	24.7
Energy and Capacity Purchase Contracts (d)	22.9	46.1	41.8	96.7	207.5
Total	$ 395.1	$ 259.7	$ 169.3	$ 1,319.5	$ 2,143.6

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) Represents short-term borrowings from the Utility Money Pool.
(c) See Note 15.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

(in millions)

Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 Years**	**Total**
Standby Letters of Credit (a)	$ -	$ 43.4	$ -	$ -	$ 43.4
Guarantees of Our Performance (b)	-	129.0	-	-	129.0
Transmission Facilities for Third Parties (c)	24.4	29.6	14.0	24.8	92.8
Total	$ 24.4	$ 202.0	$ 14.0	$ 24.8	$ 265.2

(a) We have issued standby letters of credit to third parties. These letters of credit cover debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $43 million maturing in November 2005. There is no recourse to third parties in the event these letters of credit are drawn.

(b) See Note 8.

(c) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$11,942
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(5,033)
Fair Value of New Contracts When Entered During the Period (b)	1,175
Net Option Premiums Paid/(Received) (c)	(123)
Change in Fair Value Due to Valuation Methodology Changes (d)	110
Changes in Fair Value of Risk Management Contracts (e)	1,630
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	9,701
Net Cash Flow Hedge Contracts (g)	565
Total MTM Risk Management Contract Net Assets at December 31, 2004	$10,266

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 10,107	$ 3,941	$ 14,048
Noncurrent Assets	9,504	4	9,508
Total MTM Derivative Contract Assets	19,611	3,945	23,556
Current Liabilities	(5,277)	(3,117)	(8,394)
Noncurrent Liabilities	(4,633)	(263)	(4,896)
Total MTM Derivative Contract Liabilities	(9,910)	(3,380)	(13,290)
Total MTM Derivative Contract Net Assets	$ 9,701	$ 565	$ 10,266

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (1,280)	$ (46)	$ 644	$ -	$ -	$ -	$ (682)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	6,331	1,862	1,604	781	-	-	10,578
Prices Based on Models and Other Valuation Methods (b)	(221)	(1,158)	(1,217)	279	862	1,260	(195)
Total	$ 4,830	$ 658	$ 1,031	$ 1,060	$ 862	$ 1,260	$ 9,701

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power
Beginning Balance December 31, 2003	$ (1,828)
Changes in Fair Value (a)	866
Reclassifications from AOCI to Net Income (b)	1,619
Ending Balance December 31, 2004	$ 657

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $825 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				December 31, 2003			
(in thousands)				(in thousands)			
End	High	Average	Low	End	High	Average	Low
$157	$511	$220	$75	$189	$733	$307	$73

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $120 million and $206 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,128,227	$ 1,593,943	$ 682,049
Sales to AEP Affiliates	47,039	153,568	1,008,444
TOTAL	1,175,266	1,747,511	1,690,493
OPERATING EXPENSES			
Fuel for Electric Generation	59,512	89,389	88,488
Fuel from Affiliates for Electric Generation	101,906	195,527	157,346
Purchased Energy for Resale	206,447	373,388	211,358
Purchased Electricity from AEP Affiliates	6,140	19,097	23,406
Other Operation	301,160	289,232	296,065
Maintenance	63,599	71,361	63,392
Depreciation and Amortization	122,585	197,776	222,191
Taxes Other Than Income Taxes	91,001	92,109	95,500
Income Taxes	26,897	98,092	139,014
TOTAL	979,247	1,425,971	1,296,760
OPERATING INCOME	196,019	321,540	393,733
Carrying Costs on Stranded Cost Recovery	301,644	-	-
Nonoperating Income	45,729	54,172	53,141
Nonoperating Expenses	16,790	17,273	41,910
Nonoperating Income Tax Expense	108,161	7,080	3,152
Interest Charges	123,785	133,812	125,871
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	294,656	217,547	275,941
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	(120,534)	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	122	-
NET INCOME	174,122	217,669	275,941
Gain on Reacquired Preferred Stock	-	-	4
Preferred Stock Dividend Requirements	241	241	241
EARNINGS APPLICABLE TO COMMON STOCK	$ 173,881	$ 217,428	$ 275,704

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 168,888	$ 405,015	$ 826,197	$ -	$ 1,400,100
Redemption of Common Stock	(113,596)	(272,409)			(386,005)
Gain on Reacquired Preferred Stock			4		4
Common Stock Dividends			(115,505)		(115,505)
Preferred Stock Dividends			(241)		(241)
TOTAL					898,353
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $19				(36)	(36)
Minimum Pension Liability, Net of Tax of $39,375				(73,124)	(73,124)
NET INCOME			275,941		275,941
TOTAL COMPREHENSIVE INCOME					202,781
DECEMBER 31, 2002	55,292	132,606	986,396	(73,160)	1,101,134
Common Stock Dividends			(120,801)		(120,801)
Preferred Stock Dividends			(241)		(241)
TOTAL					980,092
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $965				(1,792)	(1,792)
Minimum Pension Liability, Net of Tax of $7,043				13,080	13,080
NET INCOME			217,669		217,669

TOTAL COMPREHENSIVE INCOME					228,957
DECEMBER 31, 2003	55,292	132,606	1,083,023	(61,872)	1,209,049
Common Stock Dividends			(172,000)		(172,000)
Preferred Stock Dividends			(241)		(241)
TOTAL COMPREHENSIVE INCOME					1,036,808
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,338				2,485	2,485
Minimum Pension Liability, Net of Taxof $31,790				55,228	55,228
NET INCOME			174,122		174,122
TOTAL COMPREHENSIVE INCOME					231,835
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Transmission	$ 788,371	$ 767,970
Distribution	1,433,380	1,376,761
General	220,435	221,354
Construction Work in Progress	50,612	58,953
Total	2,492,798	2,425,038
Accumulated Depreciation and Amortization	725,225	695,359
TOTAL - NET	1,767,573	1,729,679
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,577	1,302
Bond Defeasance Funds	22,110	-
Other Investments	-	4,639
TOTAL	23,687	5,941
CURRENT ASSETS		
Cash and Cash Equivalents	-	760
Other Cash Deposits	135,132	65,122
Advances to Affiliates	-	60,699
Accounts Receivable:		
Customers	157,431	146,630
Affiliated Companies	67,860	78,484
Accrued Unbilled Revenues	21,589	23,077
Allowance for Uncollectible Accounts	(3,493)	(1,710)
Materials and Supplies	12,288	11,707
Risk Management Assets	14,048	22,051
Margin Deposits	1,891	3,230
Prepayments and Other Current Assets	9,151	10,635
TOTAL	415,897	420,685
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	15,236	3,249
Wholesale Capacity Auction True-Up	559,973	480,000
Unamortized Loss on Reacquired Debt	11,842	9,086
Designated for Securitization	1,361,299	1,289,436
Deferred Debt - Restructuring	11,596	12,015
Other	102,032	127,488
Securitized Transition Assets	642,384	689,399
Long-term Risk Management Assets	9,508	7,627
Prepaid Pension Obligations	109,628	-
Deferred Charges	36,986	51,690
TOTAL	2,860,484	2,669,990
Assets Held for Sale - Texas Generation Plants	628,149	1,028,134
TOTAL ASSETS	$ 5,695,790	$ 5,854,429

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - $25 Par Value Per Share:		
Authorized - 12,000,000 Shares		
Outstanding - 2,211,678 Shares	$ 55,292	$ 55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,084,904	1,083,023
Accumulated Other Comprehensive Loss	(4,159)	(61,872)
Total Common Shareholders Equity	1,268,643	1,209,049
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders Equity	1,274,583	1,214,989
Long-term Debt - Nonaffiliated	1,541,552	2,053,974
TOTAL	2,816,135	3,268,963
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	365,742	237,651
Advances from Affiliates	207	-
Accounts Payable:		
General	109,688	90,004
Affiliated Companies	64,045	74,209
Customer Deposits	6,147	1,517
Taxes Accrued	184,014	67,018
Interest Accrued	41,227	43,196
Risk Management Liabilities	8,394	17,888
Obligations Under Capital Leases	412	407
Other	20,115	23,248
TOTAL	799,991	555,138
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,247,111	1,244,912
Long-term Risk Management Liabilities	4,896	2,660
Regulatory Liabilities:		
Asset Removal Costs	102,624	95,415
Deferred Investment Tax Credits	107,743	112,479
Over-recovery of Fuel Costs	211,526	150,026
Retail Clawback	61,384	45,527
Other	76,653	86,706
Obligations Under Capital Leases	468	636
Deferred Credits and Other	17,276	63,833
TOTAL	1,829,681	1,802,194
Liabilities Held for Sale - Texas Generation Plants	249,983	228,134
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,695,790	$ 5,854,429

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004		2003		2002	
OPERATING ACTIVITIES						
Net Income	$ 174,122		$ 217,669		$ 275,941	
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:						
Depreciation and Amortization	122,585		197,776		222,191	
Deferred Income Taxes	16,490		19,393		113,655	
Deferred Investment Tax Credits	(4,736	)	(5,207	)	(5,207	)
Cumulative Effect of Accounting Change	-		(122	)	-	
Carrying Costs on Stranded Cost Recovery	(301,644	)	-		-	
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	120,534		-		-	
Mark-to-Market of Risk Management Contracts	2,241		(6,341	)	(1,558	)
Wholesale Capacity Auction True-up	(79,973	)	(218,000	)	(262,000	)
Pension Contribution	(61,910	)	(86	)	-	
Fuel Recovery	61,500		81,000		16,455	
Change in Other Noncurrent Assets	88,025		20,014		(83,183	)
Change in Other Noncurrent Liabilities	827		(49,390	)	123,800	
Changes in Components of Working Capital:						
Accounts Receivable, Net	18,952		15,190		(217,149	)
Fuel, Materials and Supplies	(10,641	)	15,851		(4,899	)
Accounts Payable	9,520		55,772		(6,167	)
Taxes Accrued	116,996		42,227		(58,721	)
Interest Accrued	(1,969	)	(8,009	)	27,490	
Customer Deposits	4,630		852		(26,078	)
Other Current Assets	1,689		(8,165	)	402	
Other Current Liabilities	(3,128	)	(13,046	)	13,137	
Net Cash Flows From Operating Activities	274,110		357,378		128,109	
INVESTING ACTIVITIES						
Construction Expenditures	(121,313	)	(131,925	)	(132,261	)
Change in Other Cash Deposits, Net	(70,010	)	19,490		(84,314	)
Proceeds from Sale of Assets	429,553		7,455		-	
Other	(21,669	)	-		143	
Net Cash Flows From (Used For) Investing Activities	216,561		(104,980	)	(216,432	)
FINANCING ACTIVITIES						
Change in Short-term Debt, Net - Affiliated	-		(650,000	)	-	
Change in Short-term Debt, Net - Nonaffiliated	-		-		650,000	
Issuance of Long-term Debt - Nonaffiliated	-		953,136		-	
Issuance of Long-term Debt - Affiliated	-		-		797,335	
Retirement of Long-term Debt	(380,096	)	(247,127	)	(639,492	)
Change in Advances to/from Affiliates, Net	60,906		(187,410	)	(227,566	)
Retirement of Common Stock	-		-		(386,005	)
Retirement of Preferred Stock	-		(2	)	(6	)
Dividends Paid on Common Stock	(172,000	)	(120,801	)	(115,505	)
Dividends Paid on Cumulative Preferred Stock	(241	)	(241	)	(241	)
Net Cash Flows (Used For) From Financing Activities	(491,431	)	(252,445	)	78,520	

Net Decrease in Cash and Cash Equivalents	(760)	(47)	(9,803)
Cash and Cash Equivalents at Beginning of Period	760	807	10,610
Cash and Cash Equivalents at End of Period	$ -	$ 760	$ 807

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $117,325,000, $129,491,000 and $93,120,000 and for income taxes was $(1,058,000), $49,630,000 and $95,600,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $348,000.

See Notes to Financial Statements of Registrant Subsidiaries .

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

	2004	2003
	(in thousands)	

PREFERRED STOCK:
$100 Par Value Per Share - Authorized 3,035,000 shares

Series	Call Price December 31, 2004	Number of Shares Redeemed Year Ended December 31, 2004	2003	2002	Shares Outstanding December 31, 2004	2004	2003
Not Subject to Mandatory Redemption							
4.00%	$105.75	5	11	100	41,922	$ 4,192	$ 4,192
4.20%	103.75	-	-	-	17,476	1,748	1,748
Total						$ 5,940	$ 5,940

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ 84,344	$ 117,939
Securitization Bonds	697,193	745,680
Senior Unsecured Notes	797,863	797,532
Installment Purchase Contracts	327,894	489,585
Note Payable to Trust (a)	-	140,889
Less Portion Due Within One Year	(365,742)	(237,651)
Long-term Debt Excluding Portion Due Within One Year	$ 1,541,552	$ 2,053,974

(a) See Trust Preferred Securities section of Note 16 for discussion of Note Payable to Trust.

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.250	2004 - October 1	$ -	$ 27,400
7.125	2008 - February 1	18,581	18,581
6.625	2005 - July 1	65,763	71,958
Total		$ 84,344	$ 117,939

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually. In 2004, the First Mortgage Bonds were defeased in connection with the sale of several generation plants.

Securitization Bonds outstanding were as follows:

% Rate	Final Payment Date	Maturity Date	2004	2003
			(in thousands)	
3.54	1/15/2005	1/15/2007	$ 29,386	$ 77,937
5.01	1/15/2008	1/15/2010	154,507	154,507
5.56	1/15/2010	1/15/2012	107,094	107,094
5.96	7/15/2013	7/15/2015	214,927	214,927
6.25	1/15/2016	1/15/2017	191,857	191,857
Unamortized Discount			(578)	(642)
Total			$ 697,193	$ 745,680

The Securitization Bonds mature at different times through 2017 and have a weighted average interest rate of 5.7 percent at December 31, 2004.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
5.500	2013 - February 15	$ 275,000	$ 275,000
6.650	2033 - February 15	275,000	275,000
3.000	2005 - February 15	150,000	150,000
(a)	2005 - February 15	100,000	100,000
Unamortized Discount		(2,137)	(2,468)
Total		$ 797,863	$ 797,532

(a) A floating interest rate is determined quarterly. The rate on December 31, 2004 was 3.54%.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Matagorda County Navigation District, Texas	6.000	2028 - July 1	$ 120,265	$ 120,265
	6.125	2030 - May 1	60,000	60,000
	2.150	2030 - May 1 (a)	-	111,700
	4.550	2029 - November 1 (b)	100,635	100,635
	2.350	2030 - May 1 (a)	-	50,000
Guadalupe-Blanco River Authority District, Texas	(c)	2015 - November 1	40,890	40,890
Red River Authority of Texas	6.00	2020 - June 1	6,330	6,330
	Unamortized Discount		(226)	(235)
	Total		$ 327,894	$ 489,585

(a) These bonds were reissued in February 2005.

(b) Installment Purchase Contract provides for bonds to be tendered in 2006 for 4.55% series. Therefore, this installment purchase contract has been classified for payment in 2006.
(c) A floating interest rate is determined daily. The rate on December 31, 2004 and 2003 was 2.15% and 1.30%, respectively.

Under the terms of the installment purchase contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Note Payable to Trust was outstanding as follows:

			2004		2003
% Rate	**Due**		**(in thousands)**		
8.00	2037 - April 30	$	-	$	140,889

See Trust Preferred Securities in Note 16 for discussion of Notes Payable to Trust.

At December 31, 2004, future annual long-term debt payments are as follows:

		Amount
		(in thousands)
2005	$	365,742
2006		152,900
2007		52,730
2008		68,688
2009		53,627
Later Years		1,216,548
Total Principal Amount		1,910,235
Unamortized Discount		(2,941)
Total	$	1,907,294

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TCCs consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to TCC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

AEP Texas Central Company:

We have audited the accompanying consolidated balance sheets of AEP Texas Central Company and subsidiary as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas Central Company and subsidiary as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, effective January 1, 2003; FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003; and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

AEP TEXAS NORTH COMPANY

AEP TEXAS NORTH COMPANY

SELECTED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF OPERATIONS DATA					
Operating Revenues	$ 492,145	$ 465,946	$ 450,740	$ 556,458	$ 571,064
Operating Income	61,246	68,027	7,871	33,390	52,341
Interest Charges	21,985	22,049	20,845	23,275	23,216
Income (Loss) Before Extraordinary Loss and Cumulative Effect of Accounting Change	47,659	55,663	(13,677)	12,310	27,450
Extraordinary Loss, Net of Tax	-	(177)	-	-	-
Cumulative Effect of Accounting Change, Net of Tax	-	3,071	-	-	-
Net Income (Loss)	47,659	58,557	(13,677)	12,310	27,450
BALANCE SHEETS DATA					
Electric Utility Plant	$ 1,182,327	$ 1,233,427	$ 1,201,747	$ 1,260,872	$ 1,229,339
Accumulated Depreciation and Amortization	405,933	460,513	446,818	475,036	447,802
Net Electric Utility Plant	$ 776,394	$ 772,914	$ 754,929	$ 785,836	$ 781,537
Total Assets	$ 1,051,529	$ 989,009	$ 952,149	$ 936,001	$ 1,154,743
Common Shareholder's Equity	310,421	238,275	180,744	245,535	262,153
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357	2,367	2,367	2,367
Long-term Debt (a)	314,357	356,754	132,500	255,967	255,843
Obligations Under Capital Leases (a)	534	473	-	-	-

(a) Including portion due within one year.

AEP TEXAS NORTH COMPANY

MANAGEMENTS NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

TNC is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power in west and central Texas. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pools sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities, rural electric cooperatives and retail electric providers (REPs) in Texas.

Power pool members are compensated for energy delivered to other members based upon the delivering members incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

Net Income decreased $11 million for 2004 primarily driven by lower margins from risk management activities, a provision for potential loss on fuel disputes and a 2003 Cumulative Effect of Accounting Change.

Operating Income

Operating Income decreased $7 million primarily due to:

- A $31 million net increase in fuel and purchased power expenses. KWHs purchased increased 17% while the average cost per KWH purchased decreased 23%. KWH generation increased 1% while the generation cost per KWH increased 20% primarily due to a one-time provision for possible loss in fuel disputes.
- A $5 million decrease in margins from risk management activities.
- A $5 million decrease in other electric revenue, primarily Qualified Scheduling Entity (QSE) fees and miscellaneous service revenue.
- A $3 million increase in Depreciation and Amortization expenses primarily due to the 2003 amortization credit adjustment for excess earnings accruals related to a final court determination (see Texas Restructuring and Unrefunded Excess Earnings section of Note 6).
- A $2 million increase in Taxes Other Than Income Taxes primarily due to higher accrued property taxes attributable to changes in property values, property tax rates, net fixed asset increases, accrual update adjustments and timing of prior period true-ups.
- A $2 million decrease in Reliability Must Run (RMR) revenues from ERCOT, which include a fuel recovery increase of $2 million and a fixed cost decrease of $4 million. We will no longer have RMR revenues after 2004. In 2004, RMR revenues totaled $51 million of which $9 million was for reimbursement of fixed cost.
- A $2 million increase in Other Operation expenses primarily due to higher ERCOT related transmission expense.
- A $2 million increase in Maintenance expenses primarily due to overhead line and pole inspection expenses.

The decrease in Operating Income was partially offset by:

- A $12 million increase in off-system sales, including those to REPs, primarily due to higher KWH sales of 2%.

- A $10 million increase in revenues due to a decrease in provision for rate refunds primarily due to fuel reconciliation issues (see TNC Fuel Reconciliations section of Note 4).
- A $10 million increase in transmission revenue primarily due to prior year adjustments recorded in 2004 for affiliated open access transmission tariff and ancillary services resulting from revised data received from ERCOT for the years 2001-2003.
- A $7 million increase in revenues from ERCOT for various services, including balancing energy and prior year adjustments made by ERCOT.
- A $7 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income decreased $6 million primarily as a result of a $3 million decrease in nonutility revenue associated with energy-related construction projects for third parties and a decrease of $3 million related to risk management activities.

Nonoperating Expenses decreased $4 million primarily due to lower nonutility expenses associated with energy-related construction projects for third parties.

Income Taxes

The effective tax rates for 2004 and 2003 were 32.1% and 35.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35.0% is due to permanent differences, amortization of investment tax credits, consolidated tax savings, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to an increase in favorable federal income tax adjustments.

Extraordinary Loss

Extraordinary Loss in 2003 resulted from the cessation of SFAS 71 accounting for wholesale generation assets due to the FERC settlement case (see Extraordinary Item in Note 2).

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to a one-time after tax impact of adopting SFAS 143, Accounting for Asset Retirement Obligations, effective January 1, 2003 (see Asset Retirement Obligations in Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moodys	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payments due by Period

(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Long-term Debt (a)	$ 37.6	$ 8.1	$ -	$ 269.4	$ 315.1
Capital Lease Obligations (b)	0.2	0.2	0.1	0.1	0.6
Noncancelable Operating Leases (b)	2.2	3.4	2.8	3.0	11.4
Energy and Capacity Purchase Contracts (c)	19.9	39.9	36.2	83.8	179.8
Total	$ 59.9	$ 51.6	$ 39.1	$ 356.3	$ 506.9

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.

(b) See Note 15.
(c) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

(in millions)

Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Transmission Facilities for Third Parties (a)	$ 20.2	$ 34.0	$ 6.4	$ -	$ 60.6

(a) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effects on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$4,620
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,915)
Fair Value of New Contracts When Entered During the Period (b)	508
Net Option Premiums Paid/(Received) (c)	(53)
Change in Fair Value Due to Valuation Methodology Changes (d)	45
Changes in Fair Value of Risk Management Contracts (e)	987
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	4,192
Net Cash Flow Hedge Contracts (g)	245
Total MTM Risk Management Contract Net Assets at December 31, 2004	$4,437

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 4,368	$ 1,703	$ 6,071
Noncurrent Assets	4,107	3	4,110
Total MTM Derivative Contract Assets	8,475	1,706	10,181
Current Liabilities	(2,281)	(1,347)	(3,628)
Noncurrent Liabilities	(2,002)	(114)	(2,116)
Total MTM Derivative Contract Liabilities	(4,283)	(1,461)	(5,744)
Total MTM Derivative Contract Net Assets	$ 4,192	$ 245	$ 4,437

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (553)	$ (20)	$ 278	$ -	$ -	$ -	$ (295)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,736	805	693	338	-	-	4,572
Prices Based on Models and Other Valuation Methods (b)	(96)	(502)	(526)	121	373	545	(85)
Total	$ 2,087	$ 283	$ 445	$ 459	$ 373	$ 545	$ 4,192

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power
Beginning Balance December 31, 2003	$ (601)
Changes in Fair Value (a)	373
Reclassifications from AOCI to Net Income (b)	513
Ending Balance December 31, 2004	$ 285

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $357 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				December 31, 2003			
(in thousands)				(in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$68	$221	$95	$33	$76	$294	$123	$29

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $13 million and $33 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY

STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 440,465	$ 410,793	$ 210,315
Sales to AEP Affiliates	51,680	55,153	240,425
TOTAL	492,145	465,946	450,740
OPERATING EXPENSES			
Fuel for Electric Generation	54,442	39,082	36,081
Fuel from Affiliates for Electric Generation	46,496	44,197	64,385
Purchased Energy for Resale	134,774	87,006	80,391
Purchased Electricity from AEP Affiliates	5,211	39,409	37,582
Other Operation	87,046	85,263	104,960
Asset Impairments	-	-	42,898
Maintenance	20,602	18,961	22,295
Depreciation and Amortization	39,025	36,242	43,620
Taxes Other Than Income Taxes	22,630	20,570	22,471
Income Taxes Expense (Credit)	20,673	27,189	(11,814)
TOTAL	430,899	397,919	442,869
OPERATING INCOME	61,246	68,027	7,871
Nonoperating Income	62,036	68,451	53,884
Nonoperating Expenses	51,802	55,692	54,876
Nonoperating Income Tax Expense (Credit)	1,836	3,074	(289)
Interest Charges	21,985	22,049	20,845
Income (Loss) Before Extraordinary Loss and Cumulative Effect of Accounting Change	47,659	55,663	(13,677)
Extraordinary Loss, Net of Tax	-	(177)	-
Cumulative Effect of Accounting Change, Net of Tax	-	3,071	-
NET INCOME (LOSS)	47,659	58,557	(13,677)
Gain on Reacquired Preferred Stock	-	3	-
Preferred Stock Dividend Requirements	103	104	104
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 47,556	$ 58,456	$ (13,781)

The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY

STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	**Paid-in Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total**
DECEMBER 31, 2001	$ 137,214	$ 2,351	$ 105,970	$ -	$ 245,535
Common Stock Dividends			(20,247)		(20,247)
Preferred Stock Dividends			(104)		(104)
TOTAL COMPREHENSIVE LOSS					225,184
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $8				(15)	(15)
Minimum Pension Liability, Net of Tax of $16,557				(30,748)	(30,748)
NET LOSS			(13,677)		(13,677)
TOTAL COMPREHENSIVE LOSS					(44,440)
DECEMBER 31, 2002	137,214	2,351	71,942	(30,763)	180,744
Common Stock Dividends			(4,970)		(4,970)
Preferred Stock Dividends			(104)		(104)
Gain on Reacquired Preferred Stock			3		3
TOTAL COMPREHENSIVE INCOME					175,673
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $316				(586)	(586)
Minimum Pension Liability, Net of Tax of $2,498				4,631	4,631
NET INCOME			58,557		58,557
TOTAL COMPREHENSIVE INCOME					62,602
DECEMBER 31, 2003	137,214	2,351	125,428	(26,718)	238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(103)		(103)
TOTAL COMPREHENSIVE INCOME					236,172
Other Comprehensive Income (Loss), Net of Taxes:					

Cash Flow Hedges, Net of Tax of $477				886	886
Minimum Pension Liability, Net of Tax of $13,841				25,704	25,704
NET INCOME			47,659		47,659
TOTAL COMPREHENSIVE INCOME					74,249
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY

BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 287,212	$ 360,463
Transmission	281,359	268,695
Distribution	474,961	456,278
General	115,174	117,792
Construction Work in Progress	23,621	30,199
Total	1,182,327	1,233,427
Accumulated Depreciation and Amortization	405,933	460,513
TOTAL - NET	776,394	772,914
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,407	1,286
CURRENT ASSETS		
Other Cash Deposits	2,308	2,863
Advances to Affiliates	51,504	41,593
Accounts Receivable:		
Customers	90,109	56,670
Affiliated Companies	21,474	28,910
Accrued Unbilled Revenues	3,789	4,871
Miscellaneous	-	3,411
Allowance for Uncollectible Accounts	(787)	(175)
Unbilled Construction Costs	22,065	16,943
Fuel Inventory	3,148	10,925
Materials and Supplies	8,273	8,866
Risk Management Assets	6,071	10,340
Margin Deposits	818	1,285
Prepayments and Other	1,053	1,834
TOTAL	209,825	188,336
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Under Recovery of Fuel Costs	-	6,180
Deferred Debt - Restructuring	6,093	6,579
Unamortized Loss on Reacquired Debt	2,147	3,929
Other	3,783	3,332
Long-term Risk Management Assets	4,110	3,106
Prepaid Pension Obligations	44,911	-
Deferred Charges	2,859	3,347
TOTAL	63,903	26,473
TOTAL ASSETS	$ 1,051,529	$ 989,009

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - $25 Par Value per share:		
Authorized - 7,800,000 Shares		
Outstanding - 5,488,560 Shares	$ 137,214	$ 137,214
Paid-in Capital	2,351	2,351
Retained Earnings	170,984	125,428
Accumulated Other Comprehensive Income (Loss)	(128)	(26,718)
Total Common Shareholders Equity	310,421	238,275
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholders Equity	312,778	240,632
Long-term Debt - Nonaffiliated	276,748	314,249
TOTAL	589,526	554,881
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	37,609	42,505
Accounts Payable:		
General	22,444	28,190
Affiliated Companies	52,801	40,601
Customer Deposits	1,020	161
Taxes Accrued	37,269	22,877
Interest Accrued	5,044	6,038
Risk Management Liabilities	3,628	8,658
Obligations Under Capital Leases	220	203
Other	9,628	9,419
TOTAL	169,663	158,652
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	138,465	113,019
Long-term Risk Management Liabilities	2,116	1,094
Regulatory Liabilities:		
Asset Removal Costs	81,143	76,740
Deferred Investment Tax Credits	18,698	19,990
Over-recovery of Fuel Costs	3,920	-
Retail Clawback	13,924	11,804
Excess Earnings	13,270	14,262
SFAS 109 Regulatory Liability, Net	8,500	13,655
Other	1,319	1,826
Obligations Under Capital Leases	314	270
Deferred Credits and Other	10,671	22,816
TOTAL	292,340	275,476
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,051,529	$ 989,009

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income (Loss)	$ 47,659	$ 58,557	$ (13,677)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	39,025	36,242	43,620
Extraordinary Item	-	177	-
Asset Impairments and Investment Value Losses	-	-	42,898
Deferred Income Taxes	4,236	(3,493)	(12,275)
Deferred Investment Tax Credits	(1,292)	(1,521)	(1,271)
Cumulative Effect of Accounting Change	-	(3,071)	-
Mark-to-Market of Risk Management Contracts	428	(2,558)	(1,127)
Over/Under Fuel Recovery	10,100	15,960	14,169
Pension Contribution	(21,172)	(410)	-
Change in Other Noncurrent Assets	(8,368)	6,081	(15,719)
Change in Other Noncurrent Liabilities	13,521	(5,069)	14,985
Changes in Components of Working Capital:			
Accounts Receivable, Net	(18,779)	14,393	(80,900)
Fuel, Materials and Supplies	8,370	2,460	(2,754)
Accounts Payable	6,454	(40,140)	63,761
Taxes Accrued	14,392	19,180	(13,661)
Customer Deposits	859	45	(4,075)
Interest Accrued	(994)	3,261	(1,986)
Other Current Assets	(4,834)	(15,035)	(1,209)
Other Current Liabilities	225	(7,791)	7,590
Net Cash Flows From Operating Activities	89,830	77,268	38,369
INVESTING ACTIVITIES			
Construction Expenditures	(36,375)	(46,683)	(43,563)
Change in Other Cash Deposits, Net	555	(1,706)	(764)
Proceeds from Sale of Assets	510	688	-
Other	-	-	150
Net Cash Flows Used For Investing Activities	(35,310)	(47,701)	(44,177)
FINANCING ACTIVITIES			
Change in Short-term Debt, Net - Affiliated	-	(125,000)	125,000
Issuance of Long-term Debt	-	222,455	-
Retirement of Long-term Debt	(42,506)	-	(130,799)
Retirement of Preferred Stock	-	(10)	-
Changes in Advances to/from Affiliates, Net	(9,911)	(122,000)	29,959
Dividends Paid on Common Stock	(2,000)	(4,970)	(20,247)
Dividends Paid on Cumulative Preferred Stock	(103)	(104)	(104)
Net Cash Flows From (Used For) Financing Activities	(54,520)	(29,629)	3,809
Net Decrease in Cash and Cash Equivalents	-	(62)	(1,999)
Cash and Cash Equivalents at Beginning of Period	-	62	2,061
Cash and Cash Equivalents at End of Period	$ -	$ -	$ 62

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $20,860,000, $16,384,000 and $19,934,000 and for income taxes was $6,905,000, $16,081,000 and $15,544,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $282,000.

See Notes to Financial Statements of Registrant Subsidiaries.

AEPTEXAS NORTH COMPANY

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

						2004	2003
						(in thousands)	
PREFERRED STOCK:							
$100 Par Value Per Share - Authorized 810,000 shares							
Series	**Call Price December 31, 2004**	**Number of Shares Redeemed Year Ended December 31,**			**Shares Outstanding December 31, 2004**		
		2004	**2003**	**2002**			
Not Subject to Mandatory Redemption:							
4.40%	$107	4	102	-	23,566	$ 2,357	$ 2,357

See Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY

SCHEDULE OF LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ 45,752	$ 88,236
Installment Purchase Contracts	44,310	44,310
Senior Unsecured Notes	224,295	224,208
Less Portion Due Within One Year	(37,609)	(42,505)
Long-term Debt Excluding Portion Due Within One Year	$ 276,748	$ 314,249

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

		2004	2003
% Rate	**Due**	(in thousands)	
7.000	2004 - October 1	$ -	$ 18,469
6.125	2004 - February 1	-	24,036
6.375	2005 - October 1	37,609	37,609
7.750	2007 - June 1	8,151	8,151
Unamortized Discount		(8)	(29)
Total		$ 45,752	$ 88,236

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

		2004	2003
% Rat e	**Due**	(in thousands)	

Red River Authority of Texas	6.000	2020 - June 1				
			$	44,310	**$**	44,310

Under the terms of the Installment Purchase Contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

		2004		2003	
% Rate	**Due**		**(in thousands)**		
5.500	2013 - March 1	$	225,000	$	225,000
Unamortized Discount			(705)		(792)
Total		$	224,295	$	224,208

At December 31, 2004, future annual Long-term Debt payments are as follows:

	Amount	
		(in thousands)
2005	$	37,609
2006		-
2007		8,151
2008		-
2009		-
Later Years		269,310
Total Principal Amount		315,070
Unamortized Discount		(713)
Total	$	314,357

AEP TEXAS NORTH COMPANY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to TNCs financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to TNC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

AEP Texas North Company:

We have audited the accompanying balance sheets of AEP Texas North Company as of December 31, 2004 and 2003, and the related statements of operations, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Texas North Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, effective January 1, 2003 and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

APPALACHIAN POWER COMPANY

AND SUBSIDIARIES

APPALACHIAN POWER COMPANY

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,948,182	$ 1,957,358	$ 1,814,470	$ 1,784,259	$ 1,759,253
Operating Income	244,010	318,811	302,063	274,986	201,154
Interest Charges	98,947	115,202	116,677	120,036	148,000
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	153,115	202,783	205,492	161,818	64,906
Extraordinary Gain	-	-	-	-	8,938
Cumulative Effect of Accounting Changes, Net of Tax	-	77,257	-	-	-
Net Income	153,115	280,040	205,492	161,818	73,844
BALANCE SHEETS DATA					
Electric Utility Plant	$ 6,529,630	$ 6,140,931	$ 5,895,303	$ 5,664,657	$ 5,418,278
Accumulated Depreciation and Amortization	2,443,218	2,321,360	2,330,012	2,207,072	2,103,471
Net Electric Utility Plant	$ 4,086,412	$ 3,819,571	$ 3,565,291	$ 3,457,585	$ 3,314,807
Total Assets	$ 5,239,918	$ 4,977,011	$ 4,722,442	$ 4,572,194	$ 6,657,920
Common Shareholder's Equity	1,409,718	1,336,987	1,166,057	1,126,701	1,096,260
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784	17,790	17,790	17,790
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	-	5,360	10,860	10,860	10,860
Long-term Debt (a)	1,784,598	1,864,081	1,893,861	1,556,559	1,605,818
Obligations Under Capital Leases (a)	19,878	25,352	33,589	46,285	63,160

(a) Including portion due within one year.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS

APCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 934,000 retail customers in our service territory in southwestern Virginia and southern West Virginia. We consolidate Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pools generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each members prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each members percentage share of revenues and costs. We had a new all time peak demand in December 2004, therefore we will have an increase in our MLR percentage in 2005.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in the new environment. We are confident in our ability to participate successfully in the PJM market.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East Companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income for 2004 decreased $127 million over the prior year period largely due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003. See Cumulative Effect of Accounting Changes in Note 2 for further information. Net Income was also affected by an increase in expenses in the current year, primarily in Maintenance and Other Operation, coupled with a decrease in revenue. The unfavorable impacts on Net Income were partially offset by decreased Income Taxes.

Net Income for 2003 increased $75 million over the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003. Net Income was also affected by an increase in both Electric Generation, Transmission and Distribution and Sales to AEP Affiliates revenues, offset by an increase in purchased power and Fuel for Electric Generation expenses.

2004 Compared to 2003

Operating Income

Operating Income for 2004 decreased by $75 million from 2003 primarily due to:

A $40 million increase in Maintenance expense primarily caused by boiler plant maintenance at Amos, Clinch River, Glen Lyn, Mountaineer and Kanawha River plants in 2004.

A $24 million increase in Other Operation expense due to increased administrative and support expenses, increased insurance premiums and increased removal costs in 2004. These increases were partially offset by reduced labor costs and increased gains recorded on the dispositions of SO_2 emission allowances in 2004.

An $18 million increase in Depreciation and Amortization related to a greater depreciable base in 2004 including the addition of capitalized software costs partially offset by reduced amortization of Virginias transition generation regulatory assets.

A net $10 million increase in fuel and purchased energy expenses. Purchased energy increased $45 million due to increases in volume and price, offset by a $35 million decrease in Fuel for Electric Generation expense . The decrease in Fuel for Electric Generation expense results from accruing less fuel expense in order to match fuel revenues billed to ratepayers (See Deferred Fuel Costs section in Note 1).

A $6 million decrease in Sales to AEP Affiliates resulting from decreased power available due mainly to planned plant outages.

A $3 million decrease in Electric Generation, Transmission and Distribution revenues related to a decrease in off-system sales, including PJM transactions, offset by increased retail revenues resulting from a 28% increase in cooling degree days in the current year.

The decrease in Operating Income for 2004 was partially offset by:

A $29 million decrease in Income Taxes. See Income Taxes section below for further discussion.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $16 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Nonoperating Income Tax Credit decreased $8 million in 2004 compared to 2003. See Income Taxes section below for further discussion.

Interest Charges decreased $16 million in 2004 compared to 2003 due to reduced interest rates from refinancing higher cost debt and increased construction-related capitalized interest.

Income Taxes

The effective tax rates for 2004 and 2003 were 35.7% and 34.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, consolidated tax savings from Parent, amortization of investment tax credits, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million in 2003 was due to the implementation of SFAS 143 and EITF 02-3 (see Cumulative Effect section in Note 2).

2003 Compared to 2002

Operating Income

Operating Income for 2003 increased by $17 million from 2002 primarily due to:

- A $107 million increase in Electric Generation, Transmission and Distribution revenues related to increases in off-system sales and transmission revenues reflecting an increase in the volume of AEP Power Pool transactions as well as our relative share based on a higher MLR due to a new peak demand in January 2003.
- A $36 million increase in Sales to AEP Affiliates due to strong wholesale sales by the AEP Power Pool.
- A $24 million decrease in Other Operation expense primarily related to severance expenses of $13 million incurred in 2002 caused by the SEI initiative (see Note 9). In addition, reduced employee related expenses and insurance premiums occurred in 2003. These decreases were partially offset by an increase in transmission equalization charges due to the increase in APCos MLR.
- A $14 million decrease in Depreciation and Amortization expense primarily due to reduced amortization of generation-related regulatory assets due to the return to SFAS 71 for the West Virginia jurisdiction in the first quarter of 2003 (see West Virginia Restructuring section of Note 6).

The increase in Operating Income for 2003 was partially offset by:

- A net $150 million increase in purchased power expenses and fuel expense resulted from a $62 million increase in capacity charges caused by the increase in our MLR as described above, the increase in our relative share of the AEP Power Pool expenses and increased generation . The increase in Fuel for Electric Generation expense resulted from accruing more fuel expense in order to match fuel revenues billed to ratepayers (See Deferred Fuel Costs section of Note 1).
- A $13 million increase in Maintenance expense primarily due to increased maintenance of overhead lines resulting from severe storm damage in the first quarter of 2003 and increased overhead line maintenance throughout the year.

Other Impacts on Earnings

Nonoperating Income (Loss) decreased $36 million in 2003 compared to 2002 primarily due to unfavorable results from risk management activities.

Nonoperating Income Tax Credit increased $12 million in 2003 compared to 2002. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2003 and 2002 were 34.2% and 35.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million in 2003 was due to the implementation of SFAS 143 and EITF 02-3 (see Cumulative Effect section in Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moodys	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

Cash Flow

Cash flows for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 4,561	$ 4,133	$ 7,412
Cash flows from (used for):			
Operating activities	414,074	461,276	280,709
Investing activities	(408,395)	(327,776)	(269,376)
Financing activities	(9,704)	(133,072)	(14,612)
Net increase (decrease) in cash and cash equivalents	(4,025)	428	(3,279)
Cash and cash equivalents at end of period	$ 536	$ 4,561	$ 4,133

Operating Activities

Our net cash flows from operating activities were $414 million in 2004. We produced income of $153 million during the period and noncash expense items of $194 million for Depreciation and Amortization and $48 million for Deferred Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item; an increase in Taxes Accrued of $40 million. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extensions are filed.

Our net cash flows from operating activities were $461 million in 2003. We produced income of $280 million during the period and had a noncash expense item of $176 million for Depreciation and Amortization as a result of increased amortization for the net generation-related regulatory assets related to WV jurisdiction that were assigned to the distribution business and are being recovered through rates. Other noncash expense items include $77 million for the Cumulative Effect of Accounting Changes due to the implementation of SFAS 143 & EITF 02-3 and $56 million of Mark-to-Market of Risk Management Contracts as a result of increased gains from risk management activities. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items in 2003.

Our net cash flows from operating activities were $281 million in 2002. We produced income of $205 million during the period and noncash expense items of $189 million for Depreciation and Amortization and an increase in Other Noncurrent Assets of $50 million related to an increase in regulatory assets and deferred charges. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had one significant item; an increase in Accounts Receivable of $83 million due to timing differences with AEP Energy Services and AEPSC.

Investing Activities

Cash flows used for investing activities during 2004, 2003, and 2002 primarily reflect our construction expenditures of $452 million, $289 million, and $277 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2004, capital projects for Transmission expenditures are primarily related to the Jackson Ferry-Wyoming 765 KV line. Environmental upgrades include the installation of selective catalytic reduction (SCR) equipment on Amos Unit 2 and the flue gas desulfurization (FGD) project at the Mountaineer Plant.

Financing Activities

In 2004, we issued Senior Unsecured Notes of $125 million with a floating interest rate. We reacquired First Mortgage Bonds, Senior Unsecured Notes, and Installment Purchase Contracts of $116 million, $50 million, and $40 million, respectively, at higher stated interest rates. We also increased borrowings from the Utility Money Pool of $128 million and paid common dividends of $50 million.

In 2003, we issued two series of Senior Unsecured Notes, each in the amount of $200 million that were used to call First Mortgage Bonds, Senior Unsecured Notes and fund maturities. Additionally, we incurred obligations of $188 million in Installment Purchase Contracts to redeem higher cost Installment Purchase Contracts. In addition, we had increased borrowings from the Utility Money Pool of $44 million and paid common dividends of $128 million.

In 2002, we issued two series of Senior Unsecured Notes, one for $450 million at 4.8% and the other for $200 million at 4.3%. We reacquired First Mortgage Bonds and Junior Debentures of $150 million and $165 million, respectively. We also reduced short-term borrowing from the Utility Money Pool by $253 million and paid common dividends of $93 million.

In January 2005, we issued Senior Unsecured Notes in the amount of $200 million at a rate of 4.95%.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payments Due by Period

(in millions)

Contractual Cash Obligations		**Less Than 1 year**		**2-3 years**		**4-5 years**		**After 5 years**		**Total**
Long-term Debt (a)	$	530.0	$	442.5	$	350.0	$	467.0	$	1,789.5
Advances from Affiliates (b)		211.1		-		-		-		211.1
Capital Lease Obligations (c)		8.0		9.7		4.1		1.1		22.9
Noncancelable Operating Leases (c)		7.1		10.7		6.6		6.4		30.8
Fuel Purchase Contracts (d)		480.2		442.7		101.7		45.0		1,069.6
Energy and Capacity Purchase Contracts (e)		22.4		33.1		-		-		55.5
Total	$	1,258.8	$	938.7	$	462.4	$	519.5	$	3,179.4

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) Represents short-term borrowings from The Utility Money Pool.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$68,066	
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(34,461	)
Fair Value of New Contracts When Entered During the Period (b)	2,520	
Net Option Premiums Paid/(Received) (c)	(452	)
Change in Fair Value Due to Valuation Methodology Changes (d)	835	
Changes in Fair Value of Risk Management Contracts (e)	8,492	
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9,124	
Total MTM Risk Management Contract Net Assets	54,124	
Net Cash Flow and Fair Value Hedge Contracts (g)	(13,817	)
DETM Assignment (h)	(23,736	)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$16,571	

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow and Fair Value Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See AEP East Companies in Note 17.

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 66,911	$ 14,900	$ -	$ 81,811
Noncurrent Assets	81,226	19	-	81,245
Total MTM Derivative Contract Assets	148,137	14,919	-	163,056
Current Liabilities	(50,214)	(27,315)	(11,607)	(89,136)
Noncurrent Liabilities	(43,799)	(1,421)	(12,129)	(57,349)
Total MTM Derivative Contract Liabilities	(94,013)	(28,736)	(23,736)	(146,485)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 54,124	$ (13,817)	$ (23,736)	$ 16,571

(a) Does not include Cash Flow and Fair Value Hedges.

(b) See AEP East Companies in Note 17.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (4,720)	$ (171)	$ 2,373	$ -	$ -	$ -	$ (2,518)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	22,364	9,087	8,016	2,879	-	-	42,346
Prices Based on Models and Other Valuation Methods (b)	(947)	(951)	(992)	4,377	6,240	6,569	14,296
Total	$ 16,697	$ 7,965	$ 9,397	$ 7,256	$ 6,240	$ 6,569	$ 54,124

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow and Fair Value Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance December 31, 2003	$ 359	$ (183)	$ (1,745)	$ (1,569)
Changes in Fair Value (a)	3,894	-	(10,163)	(6,269)
Reclassifications from AOCI to Net Income (b)	(1,831)	7	338	(1,486)
Ending Balance December 31, 2004	$ 2,422	$ (176)	$ (11,570)	$ (9,324)

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,876 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				**December 31, 2003**			
	(in thousands)				**(in thousands)**		
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$577	$1,883	$812	$277	$596	$2,314	$969	$230

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $99 million and $102 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,731,619	$ 1,734,565	$ 1,627,993
Sales to AEP Affiliates	216,563	222,793	186,477
TOTAL	1,948,182	1,957,358	1,814,470
OPERATING EXPENSES			
Fuel for Electric Generation	420,187	454,901	430,963
Purchased Energy for Resale	91,173	66,084	57,091
Purchased Electricity from AEP Affiliates	370,953	351,210	234,597
Other Operation	269,349	245,308	269,426
Maintenance	175,283	135,596	122,209
Depreciation and Amortization	193,525	175,772	189,335
Taxes Other Than Income Taxes	92,624	90,087	95,249
Income Taxes	91,078	119,589	113,537
TOTAL	1,704,172	1,638,547	1,512,407
OPERATING INCOME	244,010	318,811	302,063
Nonoperating Income (Loss)	10,742	(5,661)	30,020
Nonoperating Expenses	8,657	9,534	12,525
Nonoperating Income Tax Credit	5,967	14,369	2,611
Interest Charges	98,947	115,202	116,677
Income Before Cumulative Effect of Accounting Changes	153,115	202,783	205,492
Cumulative Effect of Accounting Changes, Net of Tax	-	77,257	-
NET INCOME	153,115	280,040	205,492
Preferred Stock Dividend Requirements, Including Capital Stock Expense	3,215	3,495	2,898
EARNINGS APPLICABLE TO COMMON STOCK	$ 149,900	$ 276,545	$ 202,594

The common stock of APCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 260,458	$ 715,786	$ 150,797	$ (340)	$ 1,126,701
Common Stock Dividends			(92,952)		(92,952)
Preferred Stock Dividends			(1,442)		(1,442)
Capital Stock Expense		1,456	(1,456)		-
TOTAL					1,032,307
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $861				(1,580)	(1,580)
Minimum Pension Liability, Net of Tax of $37,779				(70,162)	(70,162)
NET INCOME			205,492		205,492
TOTAL COMPREHENSIVE INCOME					133,750
DECEMBER 31, 2002	260,458	717,242	260,439	(72,082)	1,166,057
Common Stock Dividends			(128,266)		(128,266)
Preferred Stock Dividends			(1,001)		(1,001)
Capital Stock Expense		2,494	(2,494)		-
SFAS 71 Capitalization		163			163
TOTAL					1,036,953
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $199				351	351
Minimum Pension Liability, Net of Tax of $10,577				19,643	19,643
NET INCOME			280,040		280,040
TOTAL COMPREHENSIVE INCOME					300,034
DECEMBER 31, 2003	260,458	719,899	408,718	(52,088)	1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(800)		(800)
Capital Stock Expense		2,415	(2,415)		-
TOTAL					1,286,187
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					

Cash Flow Hedges, Net of Tax of $4,176				(7,755)	(7,755)
Minimum Pension Liability, Net of Tax of $11,754				(21,829)	(21,829)
NET INCOME			153,115		153,115
TOTAL COMPREHENSIVE INCOME					123,531
DECEMBER 31, 2004	$ 260,458	$ 722,314	$ 508,618	$ (81,672)	$ 1,409,718

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 2,502,273	$ 2,287,043
Transmission	1,255,390	1,240,889
Distribution	2,070,377	2,006,329
General	302,474	294,786
Construction Work in Progress	399,116	311,884
Total	6,529,630	6,140,931
Accumulated Depreciation and Amortization	2,443,218	2,321,360
TOTAL - NET	4,086,412	3,819,571
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	20,378	20,574
Other Investments	18,775	26,668
TOTAL	39,153	47,242
CURRENT ASSETS		
Cash and Cash Equivalents	536	4,561
Other Cash Deposits	1,133	41,320
Accounts Receivable:		
Customers	126,422	133,717
Affiliated Companies	140,950	137,281
Accrued Unbilled Revenues	51,427	35,020
Miscellaneous	1,264	3,961
Allowance for Uncollectible Accounts	(5,561)	(2,085)
Risk Management Assets	81,811	71,189
Fuel	45,756	42,806
Materials and Supplies	45,644	41,959
Margin Deposits	8,329	11,525
Prepayments and Other	12,192	13,301
TOTAL	509,903	534,555
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	343,415	325,889
Transition Regulatory Assets	25,467	30,855
Unamortized Loss on Reacquired Debt	18,157	19,005
Other	36,368	41,447
Long-term Risk Management Assets	81,245	70,900
Emission Allowances	38,931	30,019
Deferred Property Taxes	37,071	35,343
Deferred Charges and Other	23,796	22,185
TOTAL	604,450	575,643
TOTAL ASSETS	$ 5,239,918	$ 4,977,011

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity		
Common Stock - No Par Value:		
Authorized - 30,000,000 Shares		
Outstanding - 13,499,500 Shares	$ 260,458	$ 260,458
Paid-in Capital	722,314	719,899
Retained Earnings	508,618	408,718
Accumulated Other Comprehensive Income (Loss)	(81,672)	(52,088)
Total Common Shareholders Equity	1,409,718	1,336,987
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholders Equity	1,427,502	1,354,771
Cumulative Preferred Stock Subject to Mandatory Redemption	-	5,360
Long-term Debt - Nonaffiliated	1,254,588	1,703,073
TOTAL	2,682,090	3,063,204
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	530,010	161,008
Advances from Affiliates	211,060	82,994
Accounts Payable:		
General	130,710	140,497
Affiliated Companies	76,314	81,812
Risk Management Liabilities	89,136	51,430
Taxes Accrued	90,404	50,259
Interest Accrued	21,076	22,113
Customer Deposits	42,822	33,930
Obligations Under Capital Leases	6,742	9,218
Other	56,645	60,289
TOTAL	1,254,919	693,550
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	852,536	803,355
Regulatory Liabilities:		
Asset Removal Costs	95,763	92,497
Over-recovery of Fuel Cost	57,843	68,704
Deferred Investment Tax Credits	30,382	30,545
Other	23,270	17,326
Employee Benefits and Pension Obligations	130,530	102,463
Long-term Risk Management Liabilities	57,349	54,327
Asset Retirement Obligations	24,626	21,776
Obligations Under Capital Leases	13,136	16,134
Deferred Credits	17,474	13,130
TOTAL	1,302,909	1,220,257
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,239,918	$ 4,977,011

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 153,115	$ 280,040	$ 205,492
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	(77,257)	-
Depreciation and Amortization	193,525	175,772	189,335
Deferred Income Taxes	47,585	24,563	16,777
Deferred Investment Tax Credits	(163)	(3,146)	(4,637)
Deferred Property Taxes	(1,728)	(20)	(1,897)
Over/Under Fuel Recovery	(10,861)	74,071	6,365
Mark-to-Market of Risk Management Contracts	5,391	56,409	(21,151)
Change in Other Noncurrent Assets	(16,474)	(12,333)	(50,236)
Change in Other Noncurrent Liabilities	26,026	31,753	(5,233)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(6,608)	(6,825)	(83,453)
Fuel, Materials and Supplies	(6,635)	4,717	11,016
Accounts Payable	(15,285)	(17,611)	27,805
Taxes Accrued	40,145	21,078	(26,402)
Customer Deposits	8,892	7,744	13,008
Interest Accrued	(1,037)	(324)	667
Other Current Assets	4,303	(11,429)	2,510
Other Current Liabilities	(6,117)	(10,325)	743
Rate Stabilization Deferral	-	(75,601)	-
Net Cash Flows From Operating Activities	414,074	461,276	280,709
INVESTING ACTIVITIES			
Construction Expenditures	(452,173)	(288,800)	(276,549)
Change in Other Cash Deposits, Net	40,187	(41,168)	6,099
Proceeds from Sale of Assets	3,591	2,192	-
Other	-	-	1,074
Net Cash Flows Used For Investing Activities	(408,395)	(327,776)	(269,376)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Nonaffiliated	124,398	580,649	647,401
Issuance of Long-term Debt - Affiliated	-	-	-
Retirement of Long-term Debt	(206,008)	(622,737)	(315,007)
Retirement of Preferred Stock	(5,360)	(5,506)	-
Change in Short-term Debt, Net	-	-	-
Change in Advances to/from Affiliates, Net	128,066	43,789	(252,612)
Dividends Paid on Common Stock	(50,000)	(128,266)	(92,952)
Dividends Paid on Cumulative Preferred Stock	(800)	(1,001)	(1,442)
Net Cash Flows Used For Financing Activities	(9,704)	(133,072)	(14,612)
Net Increase (Decrease) in Cash and Cash Equivalents	(4,025)	428	(3,279)
Cash and Cash Equivalents at Beginning of Period	4,561	4,133	7,412
Cash and Cash Equivalents at End of Period	$ 536	$ 4,561	$ 4,133

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $92,773,000, $108,045,000 and $111,528,000 and for income taxes was $(831,000), $62,673,000 and $125,120,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $3,791,000.

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

							2004	2003
							(in thousands)	
PREFERRED STOCK:								
No Par Value - Authorized 8,000,000 shares								
Series	**Call Price December 31, 2004** (a)	**Number of Shares Redeemed Year Ended December 31,**			**Shares Outstanding December 31, 2004**			
		2004	**2003**	**2002**				
Not Subject to Mandatory Redemption - $100 Par:								
4.50%	$110	3	60	6	177,836	$	17,784	$ 17,784
Subject to Mandatory Redemption - $100 Par (b):								
5.90%		22,100	25,000	-	-		-	2,210
5.92%		31,500	30,000	-	-		-	3,150
Total						$	-	$ 5,360

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is $100 per share. The aggregate involuntary liquidation price for all shares of cumulative preferred stock may not exceed $300 million. The unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.

(b) The sinking fund provisions of each series subject to mandatory redemption have been met by shares purchased in advance of the due date.

See Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT

December 31, 2004 and 2003

		2004		2003
LONG-TERM DEBT:		(in thousands)		
First Mortgage Bonds	$	224,662	$	340,269
Installment Purchase Contracts		236,759		276,477
Senior Unsecured Notes		1,320,663		1,244,813
Other Long-term Debt		2,514		2,522
Less Portion Due Within One Year		(530,010)		(161,008)
Long-term Debt Excluding Portion Due Within One Year	$	1,254,588	$	1,703,073

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

			2004		2003
% Rate	**Due**		**(in thousands)**		
7.700	2004 - September 1	$	-	$	21,000
7.850	2004 - November 1		-		50,000
8.000	2005 - May 1		50,000		50,000
6.890	2005 - June 22		30,000		30,000
6.800	2006 - March 1		100,000		100,000
7.125	2024 - May 1		-		45,000
8.000	2025 - June 1		45,000		45,000
Unamortized Discount			(338)		(731)
Total		$	224,662	$	340,269

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds, by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Industrial Development Authority	(a)	2007 - November 1	$ 17,500	$ 17,500
of Russell County, Virginia	5.000	2021 - November 1	19,500	19,500
Putnam County, West Virginia	(b)	2019 - June 1	40,000	40,000
	5.450	2019 - June 1	-	40,000
	(c)	2019 - May 1	30,000	30,000
Mason County, West Virginia	6.050	2024 - December 1	30,000	30,000
	5.500	2022 - October 1	100,000	100,000
	Unamortized Discount		(241)	(523)
	Total		$ 236,759	$ 276,477

(a) Rate is an annual long-term fixed rate of 2.70% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by us (fixed rate bonds).

(b) In December 2003, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The rate on December 31, 2004 was 1.85%.

(c) Rate is an annual long-term fixed rate of 2.80% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by us (fixed rate bonds).

Under the terms of the installment purchase contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.450	2004 - November 1	$ -	$ 50,000
4.800	2005 - June 15	450,000	450,000
4.320	2007 - November 12	200,000	200,000
3.600	2008 - May 15	200,000	200,000
6.600	2009 - May 1	150,000	150,000
5.950	2033 - May 15	200,000	200,000
(a)	2007 - June 29	125,000	-
Unamortized Discount		(4,337)	(5,187)
Total		$ 1,320,663	$ 1,244,813

(a) Floating rate determined quarterly. The rate at December 31, 2004 was 2.88%.

At December 31, 2004, future annual long-term debt payments are as follows:

		Amount
		(in thousands)
2005	$	530,010
2006		100,011
2007		342,513
2008		200,014
2009		150,017
Later Years		466,949
Total Principal Amount		1,789,514
Unamortized Discount		(4,916)
Total	$	1,784,598

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCos consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, and EITF 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003 and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

COLUMBUS SOUTHERN POWER COMPANY

AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,433,581	$ 1,431,851	$ 1,400,160	$ 1,350,319	$ 1,304,409
Operating Income	184,246	225,486	219,779	252,177	195,877
Interest Charges	54,246	50,948	53,869	68,015	80,828
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	140,258	173,147	181,173	191,900	120,202
Extraordinary Loss, Net of Tax	-	-	-	(30,024)	(25,236)
Cumulative Effect of Accounting Changes, Net of Tax	-	27,283	-	-	-
Net Income	140,258	200,430	181,173	161,876	94,966
BALANCE SHEETS DATA					
Electric Utility Plant	$ 3,691,246	$ 3,570,443	$ 3,467,626	$ 3,354,320	$ 3,266,794
Accumulated Depreciation and Amortization	1,471,950	1,389,586	1,369,153	1,283,712	1,211,728
Net Electric Utility Plant	$ 2,219,296	$ 2,180,857	$ 2,098,473	$ 2,070,608	$ 2,055,066
TOTAL ASSETS	$ 3,029,896	$ 2,838,366	$ 2,849,261	$ 2,815,708	$ 3,965,460
Common Shareholder's Equity	898,650	897,881	847,664	791,498	713,449
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	-	-	-	10,000	15,000
Long-term Debt (a)	987,626	897,564	621,626	791,848	899,615
Obligations Under Capital Leases (a)	12,514	15,618	27,610	34,887	42,932

(a) Including portion due within one year.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

MANAGEMENTS NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

CSPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 707,000 retail customers in central and southern Ohio. We consolidate Colomet, Inc., Conesville Coal Preparation Company and Simco, Inc., our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pools sales to neighboring utilities and power marketers.

The cost of the AEP Power Pools generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each members prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each members percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in the new environment. We are confident in our ability to participate successfully in the PJM market.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East Companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

During 2004, Net Income decreased by $60 million primarily due to a $27 million net of tax Cumulative Effect of Accounting Changes recorded in 2003, an $18 million increase in purchased power expenses and $14 million in expenses resulting from a December 2004 ice storm.

Operating Income

Operating Income decreased by $41 million primarily due to:

A $22 million decrease in nonaffiliated wholesale energy sales and related transmission services due to lower sales volume and the expiration of municipal contracts.

A $20 million increase in Maintenance expense primarily associated with costs incurred as a result of a major ice storm in late December 2004 and boiler overhaul work from scheduled and forced outages.
An $18 million increase in purchased power expenses primarily due to increased purchases from the AEP Power Pool and PJM regional transmission authority.
A $13 million increase in Depreciation and Amortization expense due to a greater depreciable base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.
A $9 million increase in Other Operation expense primarily relating to pension plan costs, steam removal costs and administrative and support expenses, partially offset by increased gains on the disposition of emission allowances.
A $2 million decrease in affiliated wholesale energy sales due to lower sales volume.

The decrease in Operating Income was partially offset by:

A $21 million increase in retail electric revenues resulting primarily from increased weather-related demand from residential and commercial customers during the second quarter of 2004.

A $15 million decrease in Income Taxes expense. See Income Taxes section below for further discussion.
A $9 million increase in operating revenues related to favorable results from risk management activities.

Other Impacts on Earnings

Nonoperating Income (Loss) increased $18 million primarily due to favorable results from risk management activities.

Nonoperating Income Tax Expense (Credit) increased $9 million. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2004 and 2003 were 32.5% and 29.8%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to higher state income taxes, lower consolidated tax savings from Parent, and less favorable income tax adjustments.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moodys	S&P	Fitch
Senior Unsecured Debt	A3	BBB	A-

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ 36.0	$ -	$ 112.0	$ 842.2	$ 990.2
Advances to Affiliates (b)	141.6	-	-	-	141.6
Capital Lease Obligations (c)	4.5	5.3	3.2	1.0	14.0
Noncancelable Operating Leases (c)	5.7	5.9	3.8	3.2	18.6
Fuel Purchase Contracts (d)	135.8	198.1	55.3	-	389.2
Energy and Capacity Purchase Contracts (e)	11.4	17.0	-	-	28.4
Total	$ 335.0	$ 226.3	$ 174.3	$ 846.4	$ 1,582.0

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) Represents short-term borrowings from the Utility Money Pool.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

(in millions)

Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Standby Letters of Credit (a)	$ -	$ 44.1	$ -	$ -	$ 44.1

(a) We have issued standby letters of credit to third parties. These letters of credit cover debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $44.1 million maturing in April 2007. There is no recourse to third parties in the event these letters of credit are drawn.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$38,337
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(19,805)
Fair Value of New Contracts When Entered During the Period (b)	2,493
Net Option Premiums Paid/(Received) (c)	(260)
Change in Fair Value Due to Valuation Methodology Changes (d)	898
Changes in Fair Value of Risk Management Contracts (e)	9,256
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets	30,919
Net Cash Flow Hedge Contracts (g)	1,198
DETM Assignment (h)	(13,654)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$18,463

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See AEP East Companies in Note 17.

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 38,275	$ 8,356	$ -	$ 46,631
Noncurrent Assets	46,724	11	-	46,735
Total MTM Derivative Contract Assets	84,999	8,367	-	93,366
Current Liabilities	(28,885)	(6,610)	(6,677)	(42,172)
Noncurrent Liabilities	(25,195)	(559)	(6,977)	(32,731)
Total MTM Derivative Contract Liabilities	(54,080)	(7,169)	(13,654)	(74,903)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 30,919	$ 1,198	$ (13,654)	$ 18,463

(a) Does not include Cash Flow Hedges.

(b) See AEP East Companies in Note 17.

(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (2,715)	$ (98)	$ 1,365	$ -	$ -	$ -	$ (1,448)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	12,650	5,227	4,611	1,656	-	-	24,144
Prices Based on Models and Other Valuation Methods (b)	(545)	(548)	(571)	2,518	3,590	3,779	8,223
Total	$ 9,390	$ 4,581	$ 5,405	$ 4,174	$ 3,590	$ 3,779	$ 30,919

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power
Beginning Balance December 31, 2003	$ 202
Changes in Fair Value (a)	2,304
Reclassifications from AOCI to Net Income (b)	(1,113)
Ending Balance December 31, 2004	$ 1,393

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,750 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Energy and Gas Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				**December 31, 2003**			
(in thousands)				**(in thousands)**			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$332	$1,083	$467	$160	$336	$1,303	$546	$130

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $48 million and $98 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,353,466	$ 1,347,482	$ 1,342,958
Sales to AEP Affiliates	80,115	84,369	57,202
TOTAL	1,433,581	1,431,851	1,400,160
OPERATING EXPENSES			
Fuel for Electric Generation	191,578	176,071	157,569
Fuel From Affiliates for Electric Generation	10,603	27,328	27,517
Purchased Energy for Resale	26,267	17,730	15,023
Purchased Electricity from AEP Affiliates	347,002	337,323	310,605
Other Operation	227,112	218,466	237,802
Maintenance	95,036	75,319	60,003
Depreciation and Amortization	148,529	135,964	131,624
Taxes Other Than Income Taxes	133,840	133,754	136,024
Income Taxes	69,368	84,410	104,214
TOTAL	1,249,335	1,206,365	1,180,381
OPERATING INCOME	184,246	225,486	219,779
Nonoperating Income (Loss)	10,341	(7,489)	28,280
Nonoperating Expenses	1,780	4,650	6,228
Nonoperating Income Tax Expense (Credit)	(1,697)	(10,748)	6,789
Interest Charges	54,246	50,948	53,869
Income Before Cumulative Effect of Accounting Changes	140,258	173,147	181,173
Cumulative Effect of Accounting Changes, Net of Tax	-	27,283	-
NET INCOME	140,258	200,430	181,173
Preferred Stock Dividend Requirements including CapitalStock Expense	1,015	1,016	1,365
EARNINGS APPLICABLE TO COMMON STOCK	$ 139,243	$ 199,414	$ 179,808

The common stock of CSPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 41,026	$ 574,369	$ 176,103	$ -	$ 791,498
Common Stock Dividends			(65,300)		(65,300)
Preferred Stock Dividends			(350)		(350)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					725,848
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $144				(267)	(267)
Minimum Pension Liability, Net of Taxof $31,818				(59,090)	(59,090)
NET INCOME			181,173		181,173
TOTAL COMPREHENSIVE INCOME					121,816
DECEMBER 31, 2002	41,026	575,384	290,611	(59,357)	847,664
Common Stock Dividends			(163,243)		(163,243)
Capital Stock Expense		1,016	(1,016)		-
TOTAL					684,421
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $253				469	469
Minimum Pension Liability, Net of Taxof $6,763				12,561	12,561
NET INCOME			200,430		200,430
TOTAL COMPREHENSIVE INCOME					213,460
DECEMBER 31, 2003	41,026	576,400	326,782	(46,327)	897,881
Common Stock Dividends			(125,000)		(125,000)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					772,881
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $641				1,191	1,191
Minimum Pension Liability, Net of Taxof $8,443				(15,680)	(15,680)
NET INCOME			140,258		140,258

TOTAL COMPREHENSIVE INCOME										125,769
DECEMBER 31, 2004	$	41,026	$	577,415	$	341,025	$	(60,816	) $	898,650

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 1,658,552	$ 1,610,888
Transmission	432,714	425,512
Distribution	1,300,252	1,253,760
General	167,985	166,002
Construction Work in Progress	131,743	114,281
Total	3,691,246	3,570,443
Accumulated Depreciation and Amortization	1,471,950	1,389,586
TOTAL - NET	2,219,296	2,180,857
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	22,322	22,417
Other Investments	5,147	8,663
TOTAL	27,469	31,080
CURRENT ASSETS		
Cash and Cash Equivalents	25	3,377
Other Cash Deposits	33	765
Advances to Affiliates	141,550	-
Accounts Receivable:		
Customers	41,130	47,099
Affiliated Companies	72,854	68,168
Accrued Unbilled Revenues	19,580	23,723
Miscellaneous	1,145	5,257
Allowance for Uncollectible Accounts	(674)	(531)
Fuel	34,026	14,365
Materials and Supplies	37,137	26,102
Risk Management Assets	46,631	40,095
Margin Deposits	4,848	6,636
Prepayments and Other	11,499	12,444
TOTAL	409,784	247,500
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	16,481	16,027
Transition Regulatory Assets	156,676	188,532
Unamortized Loss on Reacquired Debt	13,155	13,659
Other	25,691	24,966
Long-term Risk Management Assets	46,735	39,932
Deferred Property Taxes	64,754	62,262
Deferred Charges and Other	49,855	33,551
TOTAL	373,347	378,929
TOTAL ASSETS	$ 3,029,896	$ 2,838,366

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - No Par Value:		
Authorized - 24,000,000 Shares		
Outstanding - 16,410,426 Shares	$ 41,026	$ 41,026
Paid-in Capital	577,415	576,400
Retained Earnings	341,025	326,782
Accumulated Other Comprehensive Income (Loss)	(60,816)	(46,327)
Total Common Shareholders Equity	898,650	897,881
Preferred Stock - No Shares Outstanding	-	-
Authorized - 2,500,000 Shares at $100 Par Value		
Authorized - 7,000,000 Shares at $25 Par Value		
Total Shareholders Equity	898,650	897,881
Long-term Debt:		
Nonaffiliated	851,626	886,564
Affiliated	100,000	-
Total Long-term Debt	951,626	886,564
TOTAL	1,850,276	1,784,445
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	36,000	11,000
Advances from Affiliates, Net	-	6,517
Accounts Payable:		
General	63,606	58,220
Affiliated Companies	45,745	53,572
Customer Deposits	24,890	19,727
Taxes Accrued	195,284	132,853
Interest Accrued	16,320	16,528
Risk Management Liabilities	42,172	28,966
Obligations Under Capital Leases	3,854	4,221
Other	24,338	25,364
TOTAL	452,209	356,968
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	464,545	458,498
Regulatory Liabilities:		
Asset Removal Costs	103,104	99,119
Deferred Investment Tax Credits	27,933	30,797
Employee Benefits and Pension Obligations	62,778	40,341
Long-term Risk Management Liabilities	32,731	30,598
Obligations Under Capital Leases	8,660	11,397
Asset Retirement Obligations	11,585	8,740
Deferred Credits and Other	16,075	17,463
TOTAL	727,411	696,953
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 3,029,896	$ 2,838,366

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 140,258	$ 200,430	$ 181,173
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	(27,283)	-
Depreciation and Amortization	148,529	135,964	131,753
Deferred Income Taxes	13,395	(4,514)	23,292
Deferred Investment Tax Credits	(2,864)	(3,110)	(3,270)
Deferred Property Tax	(2,492)	(529)	(13,732)
Mark-to-Market of Risk Management Contracts	2,887	41,830	(16,667)
Change in Other Noncurrent Assets	(18,591)	(12,162)	(19,747)
Change in Other Noncurrent Liabilities	2,351	(21,286)	(17,303)
Changes in Components of Working Capital:			
Accounts Receivable, Net	9,681	(5,590)	(9,576)
Fuel, Materials and Supplies	(30,696)	9,812	(1,002)
Accounts Payable	(2,441)	(59,543)	26,949
Taxes Accrued	62,431	20,681	(4,192)
Interest Accrued	(208)	6,730	(1,108)
Customer Deposits	5,163	5,009	8,834
Other Current Assets	2,731	(11,770)	21,426
Other Current Liabilities	(1,394)	7,514	(9,829)
Net Cash Flows From Operating Activities	328,740	282,183	297,001
INVESTING ACTIVITIES			
Construction Expenditures	(149,788)	(136,291)	(136,800)
Change in Other Cash Deposits, Net	732	16	58
Proceeds from Sale of Assets	3,393	1,644	730
Net Cash Flows Used For Investing Activities	(145,663)	(134,631)	(136,012)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Affiliated	100,000	-	160,000
Issuance of Long-term Debt - Nonaffiliated	89,883	643,097	-
Change in Advances to/from Affiliates, Net	(148,067)	37,774	(212,641)
Retirement of Long-term Debt - Nonaffiliated	(103,245)	(212,500)	(133,343)
Retirement of Long-term Debt - Affiliated	-	(160,000)	(200,000)
Retirement of Cumulative Preferred Stock	-	-	(10,000)
Change in Short-term Debt - Affiliates	-	(290,000)	290,000
Dividends Paid on Common Stock	(125,000)	(163,243)	(65,300)
Dividends Paid on Cumulative Preferred Stock	-	-	(525)
Net Cash Flows Used For Financing Activities	(186,429)	(144,872)	(171,809)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,352)	2,680	(10,820)
Cash and Cash Equivalents at Beginning of Period	3,377	697	11,517
Cash and Cash Equivalents at End of Period	$ 25	$ 3,377	$ 697

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $48,461,000, $42,601,000 and $53,514,000 and for income taxes was $(5,281,756), $63,907,000 and $117,591,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $1,302,000. There were no noncash capital lease acquisitions in 2003 or 2002.

See Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ -	$ 10,944
Installment Purchase Contracts	92,077	91,329
Senior Unsecured Notes	795,549	795,291
Notes Payable - Affiliated	100,000	-
Less Portion Due Within One Year	(36,000)	(11,000)
Long-term Debt Excluding Portion Due Within One Year	$ 951,626	$ 886,564

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
7.60	2024 - May 1	$ -	$ 11,000
Unamortized Discount		-	(56)
Total		$ -	$ 10,944

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by the Ohio Air Quality Development Authority:

% Rate	Due	2004	2003
		(in thousands)	
6.375	2020 - December 1	$ -	$ 48,550
6.250	2020 - December 1	-	43,695
(a)	2038 - December 1	43,695	-
(b)	2038 - December 1	48,550	-
Unamortized Discount		(168)	(916)
Total		$ 92,077	$ 91,329

(a) A floating interest rate is determined weekly and paid monthly. The rate on December 31, 2004 was 2.00%. The bonds would be subject to mandatory tender on April 27, 2007 if the letter of credit backing this issuance were not renewed at that time or if the current letter of credit provider were replaced by a new provider.

(b) In 2004, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2004 ranged from 1.05% to 1.75% and averaged 1.50%. The rate on December 31, 2004 was 1.75%. Interest payments are made every 35 days.

Under the terms of the Installment Purchase Contracts, we are required to pay amounts sufficient to enable the payment of interest on and the principal of related pollution control revenue bonds (at stated maturities and upon mandatory redemptions) issued to finance the construction of pollution control facilities at the Zimmer Plant.

Senior Unsecured Notes outstanding were as follows:

		2004	2003
% Rate	**Due**	**(in thousands)**	
6.850	2005 - October 3	$ 36,000	$ 36,000
6.510	2008 - February 1	52,000	52,000
6.550	2008 - June 26	60,000	60,000
4.400	2010 - December 1	150,000	150,000
5.500	2013 - March 1	250,000	250,000
6.600	2033 - March 1	250,000	250,000
Unamortized Discount		(2,451)	(2,709)
Total		$ 795,549	$ 795,291

Notes Payable to Parent were as follows:

		2004	2003
% Rate	**Due**	**(in thousands)**	
4.64	2010 - March 15	$ 100,000	$ -

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 36,000
2006	-
2007	-
2008	112,000
2009	-

Later Years		842,245	
Total Principal Amount		990,245	
Unamortized Discount		(2,619	)
Total	$	987,626	

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to CSPCos consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of

Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets of Columbus Southern Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, and EITF 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003 and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

INDIANA MICHIGAN POWER COMPANY

AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF OPERATIONS DATA					
Operating Revenues	$ 1,661,580	$ 1,595,596	$ 1,526,764	$ 1,526,997	$ 1,488,209
Operating Income (Loss)	195,888	186,067	151,189	159,705	(34,702)
Interest Charges	69,071	83,054	93,923	93,647	107,263
Net Income (Loss) Before Cumulative Effect of Accounting Change	133,222	89,548	73,992	75,788	(132,032)
Cumulative Effect of Accounting Change, Net of Tax	-	(3,160)	-	-	-
Net Income (Loss)	133,222	86,388	73,992	75,788	(132,032)
BALANCE SHEETS DATA					
Electric Utility Plant	$ 5,562,397	$ 5,306,182	$ 5,029,958	$ 4,923,721	$ 4,871,473
Accumulated Depreciation and Amortization	2,603,479	2,490,912	2,318,063	2,198,524	2,057,542
Net Electric Utility Plant	$ 2,958,918	$ 2,815,270	$ 2,711,895	$ 2,725,197	$ 2,813,931
Total Assets	$ 4,868,141	$ 4,659,071	$ 4,837,732	$ 4,632,510	$ 5,997,087
Common Shareholders Equity	1,091,498	1,078,047	1,018,653	860,570	793,099
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,101	8,101	8,736	8,736
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	61,445	63,445	64,945	64,945	64,945
Long-term Debt (a)	1,312,843	1,339,359	1,617,062	1,652,082	1,388,939
Obligations Under Capital Leases (a)	50,732	37,843	50,848	61,933	163,173

(a) Including portion due within one year.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 579,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. We consolidate Blackhawk Coal Company and Price River Coal Company, our wholly-owned subsidiaries. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives.

The cost of the AEP Power Pools generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each members prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each members percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of each year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in the new environment. We are confident in our ability to participate successfully in the PJM market.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

During 2004, Net Income increased $47 million as gross margin (revenues less the cost of fuel and purchased energy) increased $26 million and interest charges declined $14 million. The improvement in gross margin reflects increased retail sales and the end of amortization for the Cook Plant outage settlements.

During 2003, Net Income increased $12 million including an unfavorable $3 million Cumulative Effect of Accounting Change (see Cumulative Effect of Accounting Change section of Note 2). During 2003, Net Income Before Cumulative Effect of Accounting Change increased $15 million due to reduced financing costs and an improvement in Operating Income resulting from higher margins on wholesale sales and lower Other Operation expenses.

2004 Compared to 2003

Operating Income increased $10 million primarily due to:

A $54 million increase in Electric Generation, Transmission and Distribution revenues due to an increase in commercial and industrial sales reflecting the economic recovery and the end of amortization of Cook Plant outage settlements and an increase in revenues from coal trading sales.
A $14 million decrease in Other Operation expenses primarily due to the end of amortization of Cook Plant outage settlements.
A $12 million increase in Sales to AEP Affiliates reflecting increased availability of the Cook Plant units.
A $2 million decrease in Purchased Electricity from AEP Affiliates primarily due to an increase in net generation of 11% that reduced our need to purchase power from affiliates.

The increase in Operating Income was partially offset by:

A $29 million increase in Fuel for Electric Generation expenses reflecting an increase in total generation of 11%.

A $19 million increase in Income Taxes expense. See Income Taxes section below for further discussion.
A $14 million increase in Purchased Energy for Resale expenses reflecting new costs related to PJM membership and coal trading purchases under procurement contracts.
A $10 million increase in Maintenance expenses primarily due to increased maintenance expenses at the Cook Plant and increased costs for distribution right of way, line maintenance and storm damage repair.

Other Impacts on Earnings

Nonoperating Income increased $25 million primarily due to favorable results from risk management activities and increased barging revenues.

Nonoperating Expenses decreased $6 million primarily due to a $10 million write-down in 2003 of western coal lands (see Blackhawk Coal Company section of Note 10).

Nonoperating Income Tax Expense increased $11 million. See Income Taxes section below for further discussion.

Interest Charges decreased $14 million primarily due to a reduction in outstanding long-term debt and lower interest rates from refunding higher cost debt.

Income Taxes

The effective tax rates for 2004 and 2003 were 35% and 31.5%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is due primarily to changes in flow-through of book versus tax temporary differences and an increase in state income taxes.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change of $3 million in the prior year is due to the implementation of the requirements of EITF 02-3 related to mark-to-market accounting for risk management contracts that are not derivatives (see Cumulative Effect of Accounting Change section of Note 2).

<u>2003 Compared to 2002</u>

Operating Income

Operating Income increased $35 million primarily due to:

A $69 million increase in wholesale sales including system and power optimization sales, transmission revenues and risk management activities reflecting availability of AEPs generation and market conditions.

A $45 million decrease in Other Operation expenses primarily due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits of $15 million recorded in 2002.
A $35 million increase in Sales to AEP Affiliates due to increased capacity revenue.

The increase in Operating Income was partially offset by:

A $41 million increase in Purchased Electricity from AEP Affiliates due to purchasing more power from the AEP Power Pool to support wholesale sales to nonaffiliated entities.

A $37 million decrease in retail revenues primarily due to milder summer weather and economic pressures on industrial customers. Cooling degree days declined approximately 42% this year compared with last year. Industrial revenues declined 3% from prior year.
A $12 million increase in Income Taxes expense. See Income Taxes section below for further discussion.
An $11 million increase in Fuel for Electric Generation expense reflecting an increase in the average cost of fuel and increased coal-fired generation in 2003 as Rockports availability increased.

Other Impacts on Earnings

Nonoperating Income decreased $30 million primarily due to lower margins for power sold outside of AEPs traditional market reflecting AEPs plan to exit those risk management activities.

Nonoperating Expenses increased $16 million primarily due to a $10 million write-down of western coal lands (see Blackhawk Coal Company section of Note 10).

Nononperating Income Tax Expense decreased $16 million. See Income Taxes section below for further discussion.

Interest Charges decreased $11 million primarily due to a reduction in outstanding long-term debt of $255 million which was retired in May 2003 using lower rate short-term debt.

Income Taxes

The effective tax rates for 2003 and 2002 were 31.5% and 37.7%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is due primarily to changes in flow-through of book versus tax temporary differences and federal income tax adjustments, offset, in part, by an increase in state income taxes.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change of $3 million in 2003 is due to the implementation of the requirements of EITF 02-3 (see Cumulative Effect of Accounting Change section of Note 2).

<u>Financial Condition</u>

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings, unchanged since first quarter of 2003, are as follows:

	Moodys	**S&P**	**Fitch**
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for 2004, 2003 and 2002 were as follows:

	2004	**2003**	**2002**
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 3,899	$ 3,250	$ 6,705
Cash flows from (used for):			
Operating activities	412,123	222,821	228,234
Investing activities	(174,038)	(182,779)	(155,613)
Financing activities	(241,519)	(39,393)	(76,076)
Net increase (decrease) in cash and cash equivalents	(3,434)	649	(3,455)
Cash and cash equivalents at end of period	$ 465	$ 3,899	$ 3,250

Operating Activities

Our net cash flows from operating activities were $412 million in 2004. We produced Net Income of $133 million during the period and noncash expense items of $172 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant relates to Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP Consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extension is filed.

Our net cash flows from operating activities were $223 million in 2003. We produced Net Income of $86 million during the period and noncash expense items of $171 million for Depreciation and Amortization and $78 million for the Cook Plant outage settlement agreements. The other changes in assets and liabilities represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant was a $35 million change in net accounts receivable/payable related to the timing of settlements with our affiliates and $29 million related to Taxes Accrued related to the timing of estimated federal income tax payments.

Our net cash flows from operating activities were $228 million in 2002. We produced Net Income of $74 million during the period and noncash expense items of $168 million for Depreciation and Amortization and $78 million for the Cook Plant outage settlement amortization. The other changes in assets and liabilities represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant was a $19 million change in net accounts receivable/payable related to the timing of settlements with our affiliates.

Investing Activities

Cash flows used for investing activities during 2004, 2003 and 2002 primarily reflect our construction expenditures of $177 million, $185 million and $167 million, respectively. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability. In 2004, we also invested in capital projects to improve air quality and water intake systems.

Financing Activities

Our cash flows used for financing activities were $242 million in 2004. We used cash from operations to repay short-term debt and pay common dividends. In 2004, we issued $175 million in senior unsecured notes and refunded $97 million in fixed rate installment purchase contracts and reissued at variable rate.

Financing activities for 2003 used $39 million of cash from operations primarily to pay common dividends. During 2003, we redeemed $285 million of long-term debt using short-term debt and refinanced $65 million of our installment purchase contracts at a lower fixed rate through October 2006.

During 2002, we redeemed $340 million of long-term debt and $145 million of short-term debt using cash from operations, a $125 million capital contribution from our Parent and proceeds from the issuance of $289 million of long-term debt.

In January 2005, we redeemed $61 million Cumulative Preferred Stock Subject to Mandatory Redemption.

Off-Balance Sheet Arrangements

In prior years, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant off-balance sheet arrangements:

Rockport Plant Unit 2

In 1989, AEGCo and I&M entered into a sale and leaseback transaction with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (Rockport 2). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns Rockport 2 and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell Rockport 2. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ -	$ 415.0	$ 95.0	$ 805.9	$ 1,315.9
Preferred Stock Subject to Mandatory Redemption (b)	61.4	-	-	-	61.4
Capital Lease Obligations (c)	8.4	11.6	11.1	25.3	56.4
Noncancelable Operating Leases (c)	104.0	195.2	190.2	1,019.6	1,509.0
Fuel Purchase Contracts (d)	212.1	393.8	264.0	336.3	1,206.2
Energy and Capacity Purchase Contracts (e)	12.8	19.0	-	-	31.8
Total	$ 398.7	$ 1,034.6	$ 560.3	$ 2,187.1	$ 4,180.7

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) See Schedule of Preferred Stock.
(c) See Note 15. The lease of Rockport 2 is reported in Noncancelable Operating Leases.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$41,995	
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(15,476	)
Fair Value of New Contracts When Entered During the Period (b)	-	
Net Option Premiums Paid/(Received) (c)	(291	)
Change in Fair Value Due to Valuation Methodology Changes (d)	-	
Changes in Fair Value of Risk Management Contracts (e)	1,668	
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	6,677	
Total MTM Risk Management Contract Net Assets	34,573	
Net Cash Flow and Fair Value Hedge Contracts (g)	1,101	
DETM Assignment (h)	(15,266	)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$20,408	

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow and Fair Value Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See AEP East Companies in Note 17.

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 42,797	$ 9,344	$ -	$ 52,141
Noncurrent Assets	52,245	11	-	52,256
Total MTM Derivative Contract Assets	95,042	9,355	-	104,397
Current Liabilities	(32,297)	(7,412)	(7,465)	(47,174)
Noncurrent Liabilities	(28,172)	(842)	(7,801)	(36,815)
Total MTM Derivative Contract Liabilities	(60,469)	(8,254)	(15,266)	(83,989)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 34,573	$ 1,101	$ (15,266)	$ 20,408

(a) Does not include Cash Flow and Fair Value Hedges.

(b) See AEP East Companies in Note 17.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (3,035)	$ (110)	$ 1,526	$ -	$ -	$ -	$ (1,619)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	14,145	5,845	5,156	1,852	-	-	26,998
Prices Based on Models and Other Valuation Methods (b)	(610)	(613)	(638)	2,816	4,014	4,225	9,194
Total	$ 10,500	$ 5,122	$ 6,044	$ 4,668	$ 4,014	$ 4,225	$ 34,573

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow and Fair Value Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 222	$ -	$ 222

Changes in Fair Value (a)	2,564	(5,705)	(3,141)
Reclassifications from AOCI to Net Income (b)	(1,228)	71	(1,157)
Ending Balance December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,386 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				**December 31, 2003**			
(in thousands)				**(in thousands)**			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$371	$1,211	$522	$178	$368	$1,429	$598	$142

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $53 million and $79 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,400,406	$ 1,346,393	$ 1,312,626
Sales to AEP Affiliates	261,174	249,203	214,138
TOTAL	1,661,580	1,595,596	1,526,764
OPERATING EXPENSES			
Fuel for Electric Generation	279,518	250,890	239,455
Purchased Energy for Resale	41,888	28,327	23,443
Purchased Electricity from AEP Affiliates	272,452	274,400	233,724
Other Operation	403,702	417,636	462,707
Maintenance	168,304	158,281	151,602
Depreciation and Amortization	172,099	171,281	168,070
Taxes Other Than Income Taxes	57,344	57,788	57,721
Income Taxes	70,385	50,926	38,853
TOTAL	1,465,692	1,409,529	1,375,575
OPERATING INCOME	195,888	186,067	151,189
Nonoperating Income	79,247	53,928	84,084
Nonoperating Expenses	71,612	77,171	61,374
Nonoperating Income Tax Expense (Credit)	1,230	(9,778)	5,984
Interest Charges	69,071	83,054	93,923
Net Income Before Cumulative Effect of Accounting Change	133,222	89,548	73,992
Cumulative Effect of Accounting Change, Net of Tax	-	(3,160)	-
NET INCOME	133,222	86,388	73,992
Preferred Stock Dividend Requirements including Capital Stock Expense	474	2,509	4,601
EARNINGS APPLICABLE TO COMMON STOCK	$ 132,748	$ 83,879	$ 69,391

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 56,584	$ 733,216	$ 74,605	$ (3,835)	$ 860,570
Capital Contribution from Parent Company		125,000			125,000
Preferred Stock Dividends			(4,467)		(4,467)
Capital Stock Expense		344	(134)		210
TOTAL					981,313
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,911				3,549	3,549
Minimum Pension Liability, Net of Tax of $21,646				(40,201)	(40,201)
NET INCOME			73,992		73,992
TOTAL COMPREHENSIVE INCOME					37,340
DECEMBER 31, 2002	56,584	858,560	143,996	(40,487)	1,018,653
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(2,375)		(2,375)
Capital Stock Expense		134	(134)		-
TOTAL					976,278
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $273				508	508
Minimum Pension Liability, Net of Tax of $8,009				14,873	14,873
NET INCOME			86,388		86,388
TOTAL COMPREHENSIVE INCOME					101,769
DECEMBER 31, 2003	56,584	858,694	187,875	(25,106)	1,078,047
Common Stock Dividends			(99,293)		(99,293)
Preferred Stock Dividends			(340)		(340)
Capital Stock Expense		141	(134)		7
TOTAL					978,421
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,314				(4,298)	(4,298)

Minimum Pension Liability, Net of Tax of $8,533				(15,847)	(15,847)
NET INCOME			133,222		133,222
TOTAL COMPREHENSIVE INCOME					113,077
DECEMBER 31, 2004	$ 56,584	$ 858,835	$ 221,330	$ (45,251)	$ 1,091,498

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 3,122,883	$ 2,878,051
Transmission	1,009,551	1,000,926
Distribution	990,826	958,966
General (including nuclear fuel)	275,622	274,283
Construction Work in Progress	163,515	193,956
Total	5,562,397	5,306,182
Accumulated Depreciation and Amortization	2,603,479	2,490,912
TOTAL - NET	2,958,918	2,815,270
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,053,439	982,394
Nonutility Property, Net	50,440	52,303
Other Investments	21,848	43,797
TOTAL	1,125,727	1,078,494
CURRENT ASSETS		
Cash and Cash Equivalents	465	3,899
Other Cash Deposits	46	15
Advances to Affiliates	5,093	-
Accounts Receivable:		
Customers	62,608	63,084
Affiliated Companies	124,134	124,826
Miscellaneous	4,339	4,498
Allowance for Uncollectible Accounts	(187)	(531)
Fuel	27,218	33,968
Materials and Supplies	103,342	85,615
Risk Management Assets	52,141	44,071
Margin Deposits	5,400	7,245
Prepayments and Other	10,541	10,673
TOTAL	395,140	377,363
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	147,167	151,973
Incremental Nuclear Refueling Outage Expenses, Net	44,244	57,326
Unamortized Loss on Reacquired Debt	21,039	18,424
DOE Decontamination Fund	14,215	18,863
Other	31,015	29,691
Long-term Risk Management Assets	52,256	43,768
Emission Allowances	27,093	19,713
Deferred Property Taxes	22,372	21,916
Deferred Charges and Other Assets	28,955	26,270
TOTAL	388,356	387,944
TOTAL ASSETS	$ 4,868,141	$ 4,659,071

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - No Par Value:		
Authorized - 2,500,000 Shares		
Outstanding - 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	858,835	858,694
Retained Earnings	221,330	187,875
Accumulated Other Comprehensive Income (Loss)	(45,251)	(25,106)
Total Common Shareholders Equity	1,091,498	1,078,047
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,101
Total Shareholders Equity	1,099,582	1,086,148
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	-	63,445
Long-term Debt	1,312,843	1,134,359
TOTAL	2,412,425	2,283,952
CURRENT LIABILITIES		
Cumulative Preferred Stock Due Within One Year	61,445	-
Long-term Debt Due Within One Year	-	205,000
Advances from Affiliates	-	98,822
Accounts Payable:		
General	91,472	101,776
Affiliated Companies	51,066	47,484
Customer Deposits	29,366	21,955
Taxes Accrued	123,159	42,189
Interest Accrued	12,465	17,963
Risk Management Liabilities	47,174	31,898
Obligations Under Capital Leases	6,124	6,528
Other	70,237	57,675
TOTAL	492,508	631,290
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	315,730	337,376
Regulatory Liabilities:		
Asset Removal Costs	280,054	263,015
Deferred Investment Tax Credits	82,802	90,278
Excess ARO for Nuclear Decommissioning	245,175	215,715
Unrealized Gain on Forward Commitments	35,534	25,010
Other	33,695	36,258
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	66,472	70,179
Long-term Risk Management Liabilities	36,815	33,537
Obligations Under Capital Leases	44,608	31,315
Asset Retirement Obligations	711,769	553,219
Employee Benefits and Pension Obligations	70,027	45,751
Deferred Credits and Other	40,527	42,176
TOTAL	1,963,208	1,743,829
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 4,868,141	$ 4,659,071

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 133,222	$ 86,388	$ 73,992
Adjustments to Reconcile Net Income to Net CashFlows From OperatingActivities:			
Asset Impairments	-	10,300	-
Cumulative Effect of Accounting Change	-	3,160	-
Depreciation and Amortization	172,099	171,281	168,070
Accretion Expense	39,825	37,150	-
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	13,082	(27,754)	(26,577)
Unrecovered Fuel and Purchased Power Costs	(1,689)	37,501	37,501
Amortization of Nuclear Outage Costs	-	40,000	40,000
Deferred Income Taxes	(5,548)	(14,894)	(16,921)
Deferred Investment Tax Credits	(7,476)	(7,431)	(7,740)
Deferred Property Taxes	(456)	355	1,997
Mark-to-Market of Risk Management Contracts	2,756	43,938	(9,517)
Change in Other Noncurrent Assets	(4,799)	(22,283)	(30,397)
Change in Other Noncurrent Liabilities	(9,194)	(38,720)	9,196
Changes in Components of Working Capital:			
Accounts Receivable, Net	983	34,346	(106,683)
Fuel, Materials and Supplies	(10,977)	(7,320)	(2,084)
Accounts Payable	(6,722)	(69,396)	87,934
Taxes Accrued	80,970	(29,370)	1,798
Customer Deposits	7,411	5,294	7,391
Interest Accrued	(5,498)	(3,518)	790
Other Current Assets	1,977	(6,019)	(5,403)
Other Current Liabilities	12,157	(20,187)	4,887
Net Cash Flows From Operating Activities	412,123	222,821	228,234
INVESTING ACTIVITIES			
Construction Expenditures	(176,795)	(184,587)	(167,484)
Changes in Other Cash Deposits, Net	(31)	(28)	10,112
Proceeds from Sale of Assets	2,788	1,836	-
Other	-	-	1,759
Net Cash Flows Used For Investing Activities	(174,038)	(182,779)	(155,613)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	-	125,000
Issuance of Long-term Debt - Nonaffiliated	268,057	64,434	288,732
Retirement of Cumulative Preferred Stock	(2,011)	(1,500)	(424)
Retirement of Long-term Debt	(304,017)	(350,000)	(340,000)
Changes in Advances to/from Affiliates, Net	(103,915)	290,048	(144,917)
Dividends Paid on Common Stock	(99,293)	(40,000)	-
Dividends Paid on Cumulative Preferred Stock	(340)	(2,375)	(4,467)
Net Cash Flows Used For Financing Activities	(241,519)	(39,393)	(76,076)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,434)	649	(3,455)

Cash and Cash Equivalents at Beginning of Period	3,899	3,250	6,705
Cash and Cash Equivalents at End of Period	$ 465	$ 3,899	$ 3,250

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $70,988,000, $82,593,000 and $89,984,000 and for income taxes was $(2,244,000), $94,440,000 and $60,523,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $20,557,000, $0 and $1,023,000 in 2004, 2003 and 2002, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

Series	Call Price December 31, 2004 (a)	Number of Shares Redeemed Year Ended December 31, 2004	2003	2002	Shares Outstanding December 31, 2004	2004	2003
						(in thousands)	
PREFERRED STOCK:							
$100 Par Value Per Share - Authorized 2,250,000 shares							
$25 Par Value Per Share - Authorized 11,200,000 shares							
Not Subject to Mandatory Redemption - $100 Par:							
4.125 %	$ 106.125	-	-	20	55,369	$ 5,537	$ 5,537
4.560 %	102.000	-	-	-	14,412	1,441	1,441
4.120 %	102.728	175	-	6,326	11,055	1,106	1,123
Total						$ 8,084	$ 8,101
Subject to Mandatory Redemption - $100 Par (b):							
5.900 %		20,000	-	-	132,000	$ 13,200	$ 15,200
6.250 %		-	-	-	192,500	19,250	19,250
6.300 %		-	-	-	132,450	13,245	13,245
6.875 %		-	15,000	-	157,500	15,750	15,750
Total						$ 61,445	$ 63,445

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.

(b) All shares of each series subject to mandatory redemption were reacquired in January 2005.

See Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ -	$ 54,725
Installment Purchase Contracts	311,230	310,676
Senior Unsecured Notes	772,712	747,873
Other Long-term Debt (a)	228,901	226,085
Less Portion Due Within One Year	-	(205,000)
Long-term Debt Excluding Portion Due Within One Year	$ 1,312,843	$ 1,134,359

(a) Represents a liability for SNF disposal including interest payable to the DOE. See SNF Disposal section of Note 7.

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of our affiliates.

First Mortgage Bonds outstanding were as follows:

		2004	2003
% Rate	**Due**	(in thousands)	
7.200	2024 - February 1	$ -	$ 30,000
7.500	2024 - March 1	-	25,000
Unamortized Discount		-	(275)
Total		$ -	$ 54,725

Installment Purchase Contracts have been entered in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

			2004	2003
	% Rate	**Due**	(in thousands)	
City of Lawrenceburg, Indiana	(a)	2019 - October 1	$ 25,000	$ 25,000
	5.900	2019 - November 1	-	52,000

	(b)	2021 - November 1	52,000	-
City of Rockport, Indiana	(a)	2025 - April 1	40,000	40,000
	6.550	2025 - June 1	50,000	50,000
	(c)	2025 - June 1	50,000	50,000
	4.900 (d)	2025 - June 1	50,000	50,000
City of Sullivan, Indiana	5.950	2009 - May 1	-	45,000
	(e)	2009 - May 1	45,000	-
Unamortized Discount			(770)	(1,324)
Total			$ 311,230	$ 310,676

(a) Rate is an annual long-term fixed rate of 2.625% through October 1, 2006. After that date the rate may be a daily or weekly reset rate, commercial paper, auction or other long-term rate as designated by I&M (fixed rate bonds).

(b) In October 2004, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate on December 31, 2004 was 1.815%. The auction rate for 2004 ranged from 1.70% to 1.815% and averaged 1.73%.
(c) In 2001, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2004 ranged from 0.93% to 1.70% and averaged 1.26%. The auction rate for 2003 ranged from 0.85% to 1.35% and averaged 1.05%.
(d) Rate is fixed until June 1, 2007 (term rate bonds).
(e) In October 2004, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate on December 31, 2004 was 1.75%. The auction rate for 2004 ranged from 1.45% to 1.75% and averaged 1.59%.

The terms of the installment purchase contracts require I&M to pay amounts sufficient for the cities to pay interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. The fixed rate bonds due 2019 and 2025 are subject to mandatory tender for purchase on October 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006. The term rate bonds due 2025 are subject to mandatory tender for purchase on the term maturity date (June 1, 2007). Accordingly, the term rate bonds have been classified for repayment purposes in 2007 (the term end date). Interest payments range from every 35 days to semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.875	2004 - July 1	$ -	$ 150,000
6.125	2006 - December 15	300,000	300,000
6.450	2008 - November 10	50,000	50,000
6.375	2012 - November 1	100,000	100,000
5.050	2014 - November 15	175,000	-
6.000	2032 - December 31	150,000	150,000
Unamortized Discount		(2,288)	(2,127)
Total		$ 772,712	$ 747,873

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ -
2006	365,000
2007	50,000
2008	50,000
2009	45,000
Later Years	805,901
Total Principal Amount	1,315,901
Unamortized Discount	(3,058)
Total	$ 1,312,843

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&Ms consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, and EITF 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003 and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY

SELECTED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 450,613	$ 416,470	$ 378,683	$ 379,025	$ 389,875
Operating Income	55,321	64,744	42,197	47,678	49,738
Interest Charges	29,470	28,620	26,836	27,361	31,045
Income Before Cumulative Effect of Accounting Change	25,905	33,464	20,567	21,565	20,763
Cumulative Effect of Accounting Change,Net of Tax	-	(1,134)	-	-	-
Net Income	25,905	32,330	20,567	21,565	20,763
BALANCE SHEETS DATA					
Electric Utility Plant	$ 1,361,547	$ 1,349,746	$ 1,295,619	$ 1,128,415	$ 1,103,064
Accumulated Depreciation and Amortization	398,455	381,876	373,638	360,319	338,270
Net Electric Utility Plant	$ 963,092	$ 967,870	$ 921,981	$ 768,096	$ 764,794
Total Assets	$ 1,243,247	$ 1,221,634	$ 1,188,342	$ 1,022,833	$ 1,516,921
Common Shareholders Equity	320,980	317,138	298,018	256,130	266,713
Long-term Debt (a)	508,310	487,602	466,632	346,093	330,880
Obligations Under Capital Leases (a)	4,363	5,292	7,248	9,583	14,184

(a) Including portion due within one year.

KENTUCKY POWER COMPANY

MANAGEMENTS NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

KPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pools sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pools generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each members prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each members percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation plant to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in the new environment. We are confident in our ability to participate successfully in the PJM market.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East Companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income for 2004 decreased $6 million over the prior year primarily due to increases in planned boiler overhaul outages and administrative and support expenses.

2004 Compared to 2003

Operating Income

Operating Income for 2004 decreased by $9 million from 2003 primarily due to:

- A $25 million increase in Fuel for Electric Generation expenses resulting from an increase in the cost of coal consumed and a 6% increase in electric generation.
- An $8 million increase in Purchased Energy for Resale expenses primarily related to coal trading purchases from procurement contracts.
- A $5 million increase in Maintenance expense caused by planned boiler overhaul outages in the first and second quarters of 2004 as well as a turbine repair outage in the fourth quarter of 2004.
- A $5 million increase in Depreciation and Amortization expense primarily related to the installation of emission control equipment at the Big Sandy plant in mid-2003.
- A $4 million increase in Other Operation expense resulting from increased administrative and support expenses in 2004.

The decrease in Operating Income for 2004 was partially offset by:

- A $32 million increase in Electric Generation, Transmission and Distribution revenues due primarily to an improvement in commercial and industrial sales, the rate increase in mid-2003 to recover the cost of emission control equipment, increased fuel recoveries related to increased fuel costs, and increased revenues related to coal trading sales.
- A $3 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $2 million increase in Sales to AEP Affiliates reflecting recovery of increased generation expenses.

Other Impacts on Earnings

Nonoperating Income increased $5 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Nonoperating Income Tax Credit decreased $2 million in 2004 compared to 2003. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2004 and 2003 were 25.1% and 22.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to less favorable federal income tax adjustments.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moodys	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Summary Obligation Information

Our contractual obligations include amounts reported on the Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period

(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Long-term Debt (a)	$ -	$ 383.0	$ 30.0	$ 95.0	$ 508.0
Capital Lease Obligations (b)	1.9	2.2	0.7	0.1	4.9
Noncancelable Operating Leases (b)	1.5	2.1	1.3	1.8	6.7
Fuel Purchase Contracts (c)	84.7	159.6	3.9	-	248.2
Energy and Capacity Purchase Contracts (d)	5.1	7.6	-	-	12.7
Total	$ 93.2	$ 554.5	$ 35.9	$ 96.9	$ 780.5

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.

(b) See Note 15.
(c) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$15,490
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(5,611)
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(106)
Change in Fair Value Due to Valuation Methodology Changes (d)	-
Changes in Fair Value of Risk Management Contracts (e)	496
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	2,422
Total MTM Risk Management Contract Net Assets	12,691
Net Cash Flow and Fair Value Hedge Contracts (g)	1,102
DETM Assignment (h)	(5,570)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$8,223

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow and Fair Value Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See AEP East Companies in Note 17.

Reconciliation of MTM Risk Management Contracts to

Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 15,691	$ 4,154	$ -	$ 19,845
Noncurrent Assets	19,063	4	-	19,067
Total MTM Derivative Contract Assets	34,754	4,158	-	38,912
Current Liabilities	(11,784)	(2,697)	(2,724)	(17,205)
Noncurrent Liabilities	(10,279)	(359)	(2,846)	(13,484)
Total MTM Derivative ContractLiabilities	(22,063)	(3,056)	(5,570)	(30,689)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 12,691	$ 1,102	$ (5,570)	$ 8,223

(a) Does not include Cash Flow and Fair Value Hedges.

(b) See AEP East Companies in Note 17.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (1,107)	$ (40)	$ 557	$ -	$ -	$ -	$ (590)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	5,236	2,133	1,882	676	-	-	9,927
Prices Based on Models and Other Valuation Methods (b)	(222)	(223)	(233)	1,027	1,464	1,541	3,354
Total	$ 3,907	$ 1,870	$ 2,206	$ 1,703	$ 1,464	$ 1,541	$ 12,691

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow and Fair Value Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 82	$ 338	$ 420
Changes in Fair Value (a)	918	-	918

Reclassifications from AOCI to Net Income (b)	(431)	(94)	(525)
Ending Balance December 31, 2004	$ 569	$ 244	$ 813

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $800 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				**December 31, 2003**			
(in thousands)				**(in thousands)**			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$135	$442	$191	$65	$136	$527	$220	$52

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $16 million and $29 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY

STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 409,023	$ 376,662	$ 350,719
Sales to AEP Affiliates	41,590	39,808	27,964
TOTAL	450,613	416,470	378,683
OPERATING EXPENSES			
Fuel for Electric Generation	99,456	74,148	65,043
Purchased Energy for Resale	8,532	963	29
Purchased Electricity from AEP Affiliates	140,758	141,690	133,002
Other Operation	51,757	47,325	52,892
Maintenance	32,802	27,328	35,089
Depreciation and Amortization	43,847	39,309	33,233
Taxes Other Than Income Taxes	9,145	8,788	8,240
Income Taxes	8,995	12,175	8,958
TOTAL	395,292	351,726	336,486
OPERATING INCOME	55,321	64,744	42,197
Nonoperating Income (Loss)	1,298	(4,036)	7,950
Nonoperating Expenses	1,568	1,124	840
Nonoperating Income Tax Expense (Credit)	(324)	(2,500)	1,904
Interest Charges	29,470	28,620	26,836
Income Before Cumulative Effect of Accounting Change	25,905	33,464	20,567
Cumulative Effect of Accounting Change, Net of Tax	-	(1,134)	-
NET INCOME	$ 25,905	$ 32,330	$ 20,567

The common stock of KPCo is wholly-owned by AEP

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY

STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 50,450	$ 158,750	$ 48,833	$ (1,903)	$ 256,130
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(21,131)		(21,131)
TOTAL COMPREHENSIVE INCOME					284,999
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,198				2,225	2,225
Minimum Pension Liability, Net of Tax of $5,262				(9,773)	(9,773)
NET INCOME			20,567		20,567
TOTAL COMPREHENSIVE INCOME					13,019
DECEMBER 31, 2002	50,450	208,750	48,269	(9,451)	298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL COMPREHENSIVE INCOME					281,570
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $53				98	98
Minimum Pension Liability, Net of Tax of $1,691				3,140	3,140
NET INCOME			32,330		32,330
TOTAL COMPREHENSIVE INCOME					35,568
DECEMBER 31, 2003	50,450	208,750	64,151	(6,213)	317,138
Common Stock Dividends			(19,501)		(19,501)
TOTAL COMPREHENSIVE INCOME					297,637
Other Comprehensive Income (Loss), Net of Taxes:					

Cash Flow Hedges, Net of Tax of $212								393		393	
Minimum Pension Liability, Net of Tax of $1,592								(2,955	)	(2,955	)
NET INCOME						25,905				25,905	
TOTAL COMPREHENSIVE INCOME										23,343	
DECEMBER 31, 2004	$	50,450	$	208,750	$	70,555	$	(8,775	) $	320,980	

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY

BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 462,641	$ 457,341
Transmission	385,667	381,354
Distribution	438,766	425,688
General	57,929	68,041
Construction Work in Progress	16,544	17,322
Total	1,361,547	1,349,746
Accumulated Depreciation and Amortization	398,455	381,876
TOTAL - NET	963,092	967,870
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	5,438	5,423
Other Investments	422	1,022
TOTAL	5,860	6,445
CURRENT ASSETS		
Cash and Cash Equivalents	127	863
Other Cash Deposits	5	23
Advances to Affiliates	16,127	-
Accounts Receivable:		
Customers	22,130	21,177
Affiliated Companies	23,046	25,327
Accrued Unbilled Revenues	7,340	5,534
Miscellaneous	94	97
Allowance for Uncollectible Accounts	(34)	(736)
Fuel	6,551	9,481
Materials and Supplies	9,385	8,831
Risk Management Assets	19,845	16,200
Margin Deposits	1,960	2,660
Prepayments and Other	1,782	1,696
TOTAL	108,358	91,153
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	103,849	99,828
Other	14,558	13,971
Long-term Risk Management Assets	19,067	16,134
Emission Allowances	9,666	7,754
Deferred Property Taxes	7,036	6,847
Deferred Charges and Other	11,761	11,632
TOTAL	165,937	156,166
TOTAL ASSETS	$ 1,243,247	$ 1,221,634

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - $50 Par Value Per Share:		
Authorized - 2,000,000 Shares		
Outstanding - 1,009,000 Shares	$ 50,450	$ 50,450
Paid-in Capital	208,750	208,750
Retained Earnings	70,555	64,151
Accumulated Other Comprehensive Income (Loss)	(8,775)	(6,213)
Total Common Shareholders Equity	320,980	317,138
Long-term Debt:		
Nonaffiliated	428,310	427,602
Affiliated	80,000	60,000
Total Long-term Debt	508,310	487,602
TOTAL	829,290	804,740
CURRENT LIABILITIES		
Accounts Payable:		
General	20,080	22,802
Affiliated Companies	24,899	22,648
Advances from Affiliates	-	38,096
Risk Management Liabilities	17,205	11,704
Taxes Accrued	9,248	7,329
Interest Accrued	6,754	6,915
Customer Deposits	12,309	9,894
Obligations Under Capital Leases	1,561	1,743
Other	9,038	8,628
TOTAL	101,094	129,759
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	227,536	212,121
Regulatory Liabilities:		
Asset Removal Costs	28,232	26,140
Deferred Investment Tax Credits	6,722	7,955
Other Regulatory Liabilities	15,622	10,591
Employee Benefits and Pension Obligations	17,729	13,999
Long-term Risk Management Liabilities	13,484	12,363
Obligations Under Capital Leases	2,802	3,549
Deferred Credits	736	417
TOTAL	312,863	287,135
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,243,247	$ 1,221,634

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 25,905	$ 32,330	$ 20,567
Adjustments to Reconcile Net Income to NetCashFlowsFromOperating Activities:			
Cumulative Effect of Accounting Changes	-	1,134	-
Depreciation and Amortization	43,847	39,309	33,233
Deferred Income Taxes	12,774	20,107	9,839
Deferred Investment Tax Credits	(1,233)	(1,210)	(1,240)
Deferred Property Taxes	(189)	(547)	(338)
Deferred Fuel Costs, Net	1,164	233	2,998
Mark-to-Market of Risk Management Contracts	1,020	15,112	(12,267)
Change in Other Noncurrent Assets	(7,269)	(15,184)	(22,187)
Change in Other Noncurrent Liabilities	8,147	6,224	(5,898)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(1,177)	2,445	(9,332)
Fuel, Materials and Supplies	2,376	2,250	3,170
Accounts Payable	(471)	(45,100)	44,529
Taxes Accrued	1,919	8,582	(11,558)
Customer Deposits	2,415	1,846	3,588
Interest Accrued	(161)	444	1,202
Other Current Assets	614	(2,229)	(812)
Other Current Liabilities	226	(3,949)	16,827
Net Cash Flows From Operating Activities	89,907	61,797	72,321
INVESTING ACTIVITIES			
Construction Expenditures	(38,475)	(81,707)	(178,700)
Change in Other Cash Deposits, Net	18	(4)	17
Proceeds from Sale of Assets	1,538	967	-
Other	-	-	217
Net Cash Flows Used For Investing Activities	(36,919)	(80,744)	(178,466)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	-	50,000
Issuance of Long-term Debt - Nonaffiliated	-	74,263	-
Issuance of Long-term Debt - Affiliated	20,000	-	274,964
Retirement of Long-term Debt - Nonaffiliated	-	(40,000)	(154,500)
Retirement of Long-term Debt - Affiliated	-	(15,000)	
Change in Advances to/from Affiliates, Net	(54,223)	14,710	(42,814)
Dividends Paid	(19,501)	(16,448)	(21,131)
Net Cash Flows From (Used For) Financing Activities	(53,724)	17,525	106,519
Net Increase (Decrease) in Cash and Cash Equivalents	(736)	(1,422)	374
Cash and Cash Equivalents at Beginning of Period	863	2,285	1,911
Cash and Cash Equivalents at End of Period	$ 127	$ 863	$ 2,285

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $28,367,000, $26,988,000 and $25,176,000 in 2004, 2003 and 2002, respectively. Cash paid (received) for income taxes was $(3,233,000), $(17,574,000) and $13,041,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $925,000, $0 and $22,000 in 2004, 2003 and 2002, respectively.
See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY

SCHEDULE OF LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
Senior Unsecured Notes	$ 428,310	$ 427,602
Notes Payable - Affiliated	80,000	60,000
Long-term Debt Excluding Portion Due Within One Year	$ 508,310	$ 487,602

There are certain limitations on establishing liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

Senior Unsecured Notes outstanding were as follows :

% Rate	Due	2004	2003
		(in thousands)	
6.910	2007 -October 1	$ 48,000	$ 48,000
6.450	2008 - November 10	30,000	30,000
5.500	2007 - July 1	125,000	125,000
4.310	2007 - November 12	80,400	80,400
4.370	2007 - December 12	69,564	69,564
5.625	2032 -December 31	75,000	75,000
Unamortized Discount		(268)	(362)
Interest Rate Hedge		614	-
Total		$ 428,310	$ 427,602

Notes Payable to Parent were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.501	2006 - May 15	$ 60,000	$ 60,000
5.250	2015 - June 1	20,000	-
Total		$ 80,000	$ 60,000

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ -
2006	60,000
2007	322,964
2008	30,000
2009	-
Later Years	95,000
Total Principal Amount	507,964
Unamortized Discount	(268)
Interest Rate Hedge	614
Total	$ 508,310

KENTUCKY POWER COMPANY

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to KPCos financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to KPCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of

Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company as of December 31, 2004 and 2003, and the related statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted EITF 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003 and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 2,236,396	$ 2,244,653	$ 2,113,125	$ 2,098,105	$ 2,140,331
Operating Income	312,372	359,667	298,329	240,710	226,827
Interest Charges	118,685	106,464	83,682	93,603	119,210
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	210,116	251,031	220,023	165,793	102,613
Extraordinary Loss, Net of Tax	-	-	-	(18,348)	(18,876)
Cumulative Effect of Accounting Changes, Net of Tax	-	124,632	-	-	-
Net Income	210,116	375,663	220,023	147,445	83,737
BALANCE SHEETS DATA					
Electric Utility Plant	$ 6,798,032	$ 6,513,591	$ 5,685,826	$ 5,390,576	$ 5,577,631
Accumulated Depreciation and Amortization	2,617,238	2,485,947	2,469,837	2,360,857	2,678,606
Net Electric Utility Plant	$ 4,180,794	$ 4,027,644	$ 3,215,989	$ 3,029,719	$ 2,899,025
TOTAL ASSETS (b)	$ 5,593,265	$ 5,374,518	$ 4,554,023	$ 4,485,787	$ 6,279,499
Common Shareholders Equity	1,473,838	1,464,025	1,233,114	1,184,785	1,181,770
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,641	16,645	16,648	16,648	16,648
Cumulative Preferred Stock Subject to . Mandatory Redemption (a)	5,000	7,250	8,850	8,850	8,850
Long-term Debt (a)(b)	2,011,060	2,039,940	1,067,314	1,203,841	1,195,493
Obligations Under Capital Leases (a)	40,733	34,688	65,626	80,666	116,581

(a) Including portion due within one year.

(b) Due to the implementation of FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003.

OHIO POWER COMPANY CONSOLIDATED

MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS

OPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 707,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. We consolidate JMG Funding LP, a variable interest entity. As a member of the AEP Power Pool, we share in the revenues and the costs of the AEP Power Pools sales to neighboring utilities and power marketers.

The cost of the AEP Power Pools generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each members prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each members percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation fleet to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in the new environment. We are confident in our ability to participate successfully in the PJM market.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Effective July 1, 2003, we consolidated JMG as a result of the implementation of FIN 46. OPCo records the depreciation, interest and other operating expenses of JMG and eliminates JMGs revenues against OPCos operating lease expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions were affected. See FIN 46 Consolidation of Variable Interest Entities section of Note 2 and Gavin Scrubber Financing Arrangement section of Note 15.

Results of Operations

During 2004, Net Income decreased by $166 million primarily due to a $125 million Cumulative Effect of Accounting Changes recorded in the first quarter of 2003. Income Before Cumulative Effect decreased $41 million primarily due to an increase in fuel cost for electric generation.

During 2003, Net Income increased $156 million including a $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003 (see Cumulative Effect of Accounting Change section of Note 2). Income Before Cumulative Effect of Accounting Changes increased $31 million primarily due to increased revenues which were allocated to us from sales made to third parties by the AEP Power Pool.

2004 Compared to 2003

Operating Income

Operating Income decreased by $47 million primarily due to:

A $29 million increase in fuel expense related to a 7% increase in the cost of coal consumed. The effect of this increase in price was partially offset by a 2.5% decrease in net generation.

A $29 million increase in Depreciation and Amortization expense primarily associated with the consolidation of JMG (there was no change in Net Income due to the consolidation of JMG). In addition, the increase is a result of a greater depreciable asset base in 2004, including capitalized software costs and the increased amortization of transition generation regulatory assets due to normal operating adjustments.
A $23 million decrease in nonaffiliated wholesale energy sales and related transmission services due to lower sales volume.
An $18 million increase in Other Operation expense primarily related to increased employee benefit expense including pension plan costs and workers' compensation and administrative and support expenses.
An $11 million increase in Maintenance expense primarily associated with costs incurred as a result of a major ice storm in December 2004.
A $3 million decrease in Sales to AEP Affiliates due to lower sales volume.

The decrease in Operating Income was partially offset by:

A $49 million decrease in Income Taxes. See Income Taxes section below for further discussion.

A $15 million increase in operating revenues related to favorable results from risk management activities.
A $7 million increase in retail electric revenues resulting from increased demand of industrial customers due to the recovering economy.

Other Impacts on Earnings

Nonoperating Income increased $146 million primarily due to sales of excess energy purchased from the Dow Chemical Company (Dow) at the Plaquemine, Louisiana plant (see Power Generation Facility section below) including the effects of a related affiliate agreement which eliminates our market exposure related to the purchases from Dow. There was no change in Net Income due to the agreement with Dow. In addition, income from nonoperating risk management activities contributed to this increase.

Nonoperating Expenses increased $120 million primarily due to the agreement to purchase excess energy from Dow at the Plaquemine, Louisiana plant (see Power Generation Facility section below). There was no change in Net Income due to the agreement with Dow.

Interest Charges increased $12 million due to the consolidation of JMG in July 2003 and its associated debt. There was no change in Net Income due to the consolidation of JMG.

Income Taxes

The effective tax rates for 2004 and 2003 were 31.4% and 35.5%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes, and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to lower state income taxes and more favorable federal income tax adjustments.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes during 2003 of $125 million is due to the one-time after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

2003 Compared to 2002

Operating Income

Operating Income increased $61 million due to:

A $47 million decrease in Other Operation expense. This decrease was primarily due to a $23 million decrease in rent expense associated with the OPCo consolidation of JMG. OPCo now records the depreciation, interest and other expenses of JMG and eliminates operating lease expense against JMGs lease revenues. There was no change in Net Income due to the consolidation of JMG. In addition, operating expenses decreased due to a $7 million pretax adjustment to the workers compensation reserve related to coal companies sold in July 2001, a $9 million decrease in expense related to post-employment benefits and an $8 million reduction in employee salary expenses.

A $22 million increase in revenues from nonaffiliated off-system sales and a $119 million increase in Sales to AEP Affiliates. The increase in nonaffiliated off-system sales is primarily the result of an 8.9% increase in the price per MWH in 2003. The increase in affiliated sales is the result of optimizing our generation capacity and selling our excess power to the AEP Power Pool.

The increase in Operating Income was partially offset by:

A $32 million increase in Fuel for Electric Generation as a result of a 9.7% increase in MWH generated.

A $32 million increase in Income Taxes. See Income Taxes section below for further discussion.

A $30 million increase in Maintenance expenses. The increase in 2003 is primarily due to increased boiler overhaul costs for planned and forced outages coupled with increased expense in maintaining overhead lines due to storm damage in southern Ohio.

A $20 million increase in Purchased Electricity from AEP Affiliates resulting from a 31% volume increase in MWHs purchased from the AEP Power Pool.
An increase in Depreciation and Amortization associated with the OPCo consolidation of JMG. Effective July 1, 2003, depreciation expense related to the assets owned by JMG is consolidated with OPCo.

Other Impacts on Earnings

Nonoperating Income decreased $34 million for the year 2003 compared to 2002 primarily due to unfavorable results from risk management activities.

Nonoperating Income Tax Expense decreased $26 million as a result of a decrease in pretax nonoperating book income and changes related to consolidated tax savings.

Interest charges increased $23 million due primarily to the consolidation of JMG and its associated debt along with replacement of lower cost floating-rate short-term debt with higher cost fixed-rate longer-term debt.

Income Taxes

The effective tax rates for 2003 and 2002 were 35.5% and 37.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes, and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moodys	**S&P**	**Fitch**
Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 7,233	$ 5,275	$ 6,727
Cash flows from (used for):			
Operating activities	563,107	373,443	478,973
Investing activities	(291,589)	(288,018)	(346,187)
Financing activities	(269,451)	(83,467)	(134,238)
Net increase (decrease) in cash and cash equivalents	2,067	1,958	(1,452)
Cash and cash equivalents at end of period	$ 9,300	$ 7,233	$ 5,275

Operating Activities

Our net cash flows from operating activities were $563 million in 2004. We produced income of $210 million during the period and a noncash expense item of $286 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $100 million change in Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extension is filed.

Our net cash flows from operating activities were $373 million in 2003. We produced income of $376 million during the period and noncash expense items of $257 million for Depreciation and Amortization and $(125) million for Cumulative Effect of Accounting Changes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant is a $(173) million change in Accounts Payable, net. The change is a result of significant reductions of accounts payable balances partially associated with a wind down of risk management activities during 2003.

Our net cash flows from operating activities were $479 million in 2002. We produced income of $220 million during the period and noncash expense items of $249 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; none of which were significant.

Investing Activities

Our net cash flows used for investing activities in 2004 were $292 million primarily due to Construction Expenditures of $345 million. Current year construction expenditures were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades.

Our net cash flows used for investing activities in 2003 were $288 million primarily due to Construction Expenditures of $250 million. The construction expenditures are primarily due to improving the service reliability for transmission and distribution, as well as environmental upgrades.

Our net cash flows used for investing activities in 2002 were $346 million primarily due to Construction Expenditures of $355 million.

Financing Activities

Our net cash flows used for financing activities in 2004 were $269 million primarily due to retirement of long-term debt and payment of dividends on common stock offset by a long-term debt issuance from AEP.

Our net cash flows used for financing activities in 2003 were $83 million due to replacing both short and long-term debt with proceeds from new borrowings.

Our net cash flows used for financing activities in 2002 were $134 million due to decreased borrowings from the Utility Money Pool, retirement of long-term debt and payment of dividends on common stock offset by short-term debt borrowings.

In January 2005, we refinanced $218 million of JMGs Installment Purchase Contracts. The new bonds bear interest at a 35-day auction rate.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ 12.4	$ 230.2	$ 132.7	$ 1,642.1	$ 2,017.4
Short-term Debt	23.5	-	-	-	23.5
Cumulative Preferred Stock Subject to Mandatory Redemption (b)	5.0	-	-	-	5.0
Capital Lease Obligations (c)	9.8	16.4	8.5	20.3	55.0
Noncancelable Operating Leases (c)	16.2	29.5	27.3	71.9	144.9
Fuel Purchase Contracts (d)	585.3	881.2	396.2	431.3	2,294.0
Energy and Capacity Purchase Contracts (e)	16.0	23.7	-	-	39.7
Total	$ 668.2	$ 1,181.0	$ 564.7	$ 2,165.6	$ 4,579.5

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) See Schedule of Preferred Stock.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

(in millions)

Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Standby Letters of Credit (a)	$ -	$ 50.6	$ -	$ -	$ 50.6

(a) We have issued standby letters of credit to third parties. These letters of credit cover debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $50.6 million maturing in December 2006. There is no recourse to third parties in the event these letters of credit are drawn.

<u>Other</u>

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated qualifying cogeneration facility for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

On September 5, 2003, TEM and OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleges that TEM has breached the PPA, and is seeking a determination of OPCos rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of OPCos breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. However, OPCo has entered into an agreement with an affiliate that eliminates OPCos market exposure related to the PPA. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the creation of protocols was not subject to arbitration, but did not rule upon the merits of TEMs claim that the PPA is not enforceable. On January 21, 2005, the District Court granted OPCo partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is now in the discovery phase, with trial scheduled to begin on March 23, 2005.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the Commercial Operations Date. Despite OPCos prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCos tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for them under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

Roll-Forward of MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$53,938	
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(27,453	)
Fair Value of New Contracts When Entered During the Period (b)	3,481	
Net Option Premiums Paid/(Received) (c)	(363	)
Change in Fair Value Due to Valuation Methodology Changes (d)	1,189	
Changes in Fair Value of Risk Management Contracts (e)	16,985	
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-	
Total MTM Risk Management Contract Net Assets	47,777	
Net Cash Flow Hedge Contracts (g)	984	
DETM Assignment (h)	(19,065	)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$29,696	

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) Net Cash Flow Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See AEP East Companies in Note 17.

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 66,053	$ 13,488	$ -	$ 79,541
Noncurrent Assets	66,712	15	-	66,727
Total MTM Derivative Contract Assets	132,765	13,503	-	146,268
Current Liabilities	(49,249)	(11,739)	(9,323)	(70,311)
Noncurrent Liabilities	(35,739)	(780)	(9,742)	(46,261)
Total MTM Derivative Contract Liabilities	(84,988)	(12,519)	(19,065)	(116,572)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 47,777	$ 984	$ (19,065)	$ 29,696

(a) Does not include Cash Flow Hedges.

(b) See AEP East Companies in Note 17.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (3,790)	$ (137)	$ 1,906	$ -	$ -	$ -	$ (2,021)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	21,296	7,499	7,133	2,313	-	-	38,241
Prices Based on Models and Other Valuation Methods (b)	(702)	(735)	(810)	3,515	5,013	5,276	11,557
Total	$ 16,804	$ 6,627	$ 8,229	$ 5,828	$ 5,013	$ 5,276	$ 47,777

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power	Foreign Currency	Total

Beginning Balance December 31, 2003	$ 268	$ (371)	$ (103)
Changes in Fair Value (a)	2,830	-	2,830
Reclassifications from AOCI to Net Income (b)	(1,499)	13	(1,486)
Ending Balance December 31, 2004	$ 1,599	$ (358)	$ 1,241

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,083 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				**December 31, 2003**			
(in thousands)				**(in thousands)**			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$464	$1,513	$652	$223	$444	$1,724	$722	$172

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $ 146 million and $214 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,654,881	$ 1,660,375	$ 1,647,923
Sales to AEP Affiliates	581,515	584,278	465,202
TOTAL	2,236,396	2,244,653	2,113,125
OPERATING EXPENSES			
Fuel for Electric Generation	645,292	616,680	584,730
Purchased Energy for Resale	64,229	63,486	67,385
Purchased Electricity from AEP Affiliates	89,355	90,821	71,154
Other Operation	386,732	369,087	416,533
Maintenance	177,584	166,438	136,609
Depreciation and Amortization	286,300	257,417	248,557
Taxes Other Than Income Taxes	177,374	175,043	176,247
Income Taxes	97,158	146,014	113,581
TOTAL	1,924,024	1,884,986	1,814,796
OPERATING INCOME	312,372	359,667	298,329
Nonoperating Income	170,128	24,495	58,289
Nonoperating Expenses	154,747	34,282	34,903
Nonoperating Income Tax Expense (Credit)	(1,048)	(7,615)	18,010
Interest Charges	118,685	106,464	83,682
Income Before Cumulative Effect of Accounting Changes	210,116	251,031	220,023
Cumulative Effect of Accounting Changes, Net of Tax	-	124,632	-
NET INCOME	210,116	375,663	220,023
Preferred Stock Dividend Requirements	733	1,098	1,258
EARNINGS APPLICABLE TO COMMON STOCK	$ 209,383	$ 374,565	$ 218,765

The common stock of OPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 321,201	$ 462,483	$ 401,297	$ (196)	$ 1,184,785
Common Stock Dividends			(97,746)		(97,746)
Preferred Stock Dividends			(1,258)		(1,258)
TOTAL COMPREHENSIVE INCOME					1,085,781
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $292				(542)	(542)
Minimum Pension Liability, Net of Tax of $38,849				(72,148)	(72,148)
NET INCOME			220,023		220,023
TOTAL COMPREHENSIVE INCOME					147,333
DECEMBER 31, 2002	321,201	462,483	522,316	(72,886)	1,233,114
Common Stock Dividends			(167,734)		(167,734)
Preferred Stock Dividends			(1,098)		(1,098)
Capital Stock Gains		1			1
TOTAL COMPREHENSIVE INCOME					1,064,283
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $342				635	635
Minimum Pension Liability, Net of Tax of $13,495				23,444	23,444
NET INCOME			375,663		375,663
TOTAL COMPREHENSIVE INCOME					399,742
DECEMBER 31, 2003	321,201	462,484	729,147	(48,807)	1,464,025
Common Stock Dividends			(174,114)		(174,114)
Preferred Stock Dividends			(733)		(733)
Capital Stock Gains		1			1
TOTAL COMPREHENSIVE INCOME					1,289,179

Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $723				1,344	1,344
Minimum Pension Liability, Net of Tax of $14,432				(26,801)	(26,801)
NET INCOME			210,116		210,116
TOTAL COMPREHENSIVE INCOME					184,659
DECEMBER 31, 2004	$ 321,201	$ 462,485	$ 764,416	$ (74,264)	$ 1,473,838

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 4,127,284	$ 4,029,515
Transmission	978,492	938,805
Distribution	1,202,550	1,156,886
General	248,749	245,434
Construction Work in Progress	240,957	142,951
Total	6,798,032	6,513,591
Accumulated Depreciation and Amortization	2,617,238	2,485,947
TOTAL - NET	4,180,794	4,027,644
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	44,774	47,015
Other	13,409	22,179
TOTAL	58,183	69,194
CURRENT ASSETS		
Cash and Cash Equivalents	9,300	7,233
Other Cash Deposits	37	51,017
Advances to Affiliates	125,971	67,918
Accounts Receivable:		
Customers	98,951	100,960
Affiliated Companies	144,175	120,532
Accrued Unbilled Revenues	10,641	17,221
Miscellaneous	7,626	736
Allowance for Uncollectible Accounts	(93)	(789)
Fuel	70,309	77,725
Materials and Supplies	55,569	65,768
Emissions Allowances	95,303	2,085
Risk Management Assets	79,541	56,265
Margin Deposits	7,056	9,296
Prepayments and Other	10,492	15,883
TOTAL	714,878	591,850
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	169,866	169,605
Transition Regulatory Assets	225,273	310,035
Unamortized Loss on Reacquired Debt	11,046	10,172
Other	22,189	22,506
Long-term Risk Management Assets	66,727	52,825
Deferred Property Taxes	70,214	67,469
Deferred Charges and Other Assets	74,095	53,218
TOTAL	639,410	685,830
TOTAL ASSETS	$ 5,593,265	$ 5,374,518

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity		
Common Stock - No Par Value:		
Authorized - 40,000,000 Shares		
Outstanding - 27,952,473 Shares	$ 321,201	$ 321,201
Paid-in Capital	462,485	462,484
Retained Earnings	764,416	729,147
Accumulated Other Comprehensive Income (Loss)	(74,264)	(48,807)
Total Common Shareholders Equity	1,473,838	1,464,025
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,641	16,645
Total Shareholders Equity	1,490,479	1,480,670
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	-	7,250
Long-term Debt:		
Nonaffiliated	1,598,706	1,608,086
Affiliated	400,000	-
Total Long-term Debt	1,998,706	1,608,086
TOTAL	3,489,185	3,096,006
Minority Interest	14,083	16,314
CURRENT LIABILITIES		
Short-term Debt - Nonaffiliated	23,498	25,941
Long-term Debt Due Within One Year - Nonaffiliated	12,354	431,854
Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	-
Accounts Payable:		
General	143,247	104,874
Affiliated Companies	116,615	101,758
Customer Deposits	22,620	17,308
Taxes Accrued	233,026	132,793
Interest Accrued	39,254	45,679
Risk Management Liabilities	70,311	38,318
Obligations Under Capital Leases	9,081	9,624
Other	74,977	71,642
TOTAL	749,983	979,791
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	943,465	933,582
Regulatory Liabilities:		
Asset Removal Costs	102,875	101,160
Deferred Investment Tax Credits	12,539	15,641
Other	-	3
Long-term Risk Management Liabilities	46,261	40,477
Deferred Credits	24,377	23,222
Employee Benefits and Pension Obligations	126,825	90,260
Obligations Under Capital Leases	31,652	25,064
Asset Retirement Obligations	45,606	42,656
Other	6,414	10,342
TOTAL	1,340,014	1,282,407

Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,593,265	$ 5,374,518

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004		2003		2002	
OPERATING ACTIVITIES						
Net Income	$ 210,116		$ 375,663		$ 220,023	
Adjustments to Reconcile Net Income to Net Cash Flows From OperatingActivities:						
Cumulative Effect of Accounting Changes	-		(124,632	)	-	
Depreciation and Amortization	286,300		257,417		248,557	
Pension and Postemployment Benefits Reserves	32,637		(75,822	)	110,298	
Deferred Income Taxes	23,329		24,482		46,010	
Deferred Investment Tax Credits	(3,102	)	(3,107	)	(3,177	)
Deferred Property Tax	(2,745	)	(848	)	(1,803	)
Mark-to-Market of Risk Management Contracts	1,171		60,064		(28,693	)
Change in Other Noncurrent Assets	(8,077	)	(23,241	)	(12,963	)
Change in Other Noncurrent Liabilities	(41,055	)	40,048		(120,864	)
Changes in Components of Working Capital:						
Accounts Receivable, Net	(22,640	)	(3,966	)	17,652	
Fuel, Materials and Supplies	(4,766	)	7,271		7,740	
Accounts Payable, Net	53,230		(173,218	)	8,704	
Taxes Accrued	100,233		21,015		(14,992	)
Interest Accrued	(6,425	)	21,533		1,130	
Customer Deposits	5,312		4,339		7,517	
Other Current Assets	(63,203	)	(13,096	)	8,783	
Other Current Liabilities	2,792		(20,459	)	(14,949	)
Net Cash Flows From Operating Activities	563,107		373,443		478,973	
INVESTING ACTIVITIES						
Construction Expenditures	(345,489	)	(249,688	)	(354,797	)
Change in Other Cash Deposits, Net	50,980		(51,007	)	2,111	
Proceeds from Sale of Assets	2,920		12,671		-	
Other	-		6		6,499	
Net Cash Flows Used For Investing Activities	(291,589	)	(288,018	)	(346,187	)
FINANCING ACTIVITIES						
Issuance of Long-term Debt - Nonaffiliated	-		988,914		-	
Issuance of Long-term Debt - Affiliated	400,000		-		-	
Change in Advances to/from Affiliates, Net	(58,053	)	(197,897	)	(170,234	)
Change in Short-term Debt - Nonaffiliated, Net	(2,443	)	(671	)	-	
Change in Short-term Debt - Affiliated, Net	-		(275,000	)	275,000	
Retirement of Long-term Debt - Nonaffiliated	(431,854	)	(128,378	)	(140,000	)
Retirement of Long-term Debt - Affiliated	-		(300,000	)	-	
Retirement of Cumulative Preferred Stock	(2,254	)	(1,603	)	-	
Dividends Paid on Common Stock	(174,114	)	(167,734	)	(97,746	)
Dividends Paid on Cumulative Preferred Stock	(733	)	(1,098	)	(1,258	)
Net Cash Flows Used For Financing Activities	(269,451	)	(83,467	)	(134,238	)
Net Increase (Decrease) in Cash and Cash Equivalents	2,067		1,958		(1,452	)
Cash and Cash Equivalents at Beginning of Period	7,233		5,275		6,727	
Cash and Cash Equivalents at End of Period	$ 9,300		$ 7,233		$ 5,275	

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $119,562,000, $77,170,000 and $81,041,000 and for income taxes was $(21,600,000), $98,923,000 and $105,058,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $14,727,000, $0 and $106,000 in 2004, 2003 and 2002, respectively. Noncash activity in 2003 included an increase in assets and liabilities of $469.6 million resulting from the consolidation of JMG (see Note 2).

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

						2004	2003
						(in thousands)	
PREFERRED STOCK:							
$100 Par Value per share - Authorized 3,762,403 shares							
$25 Par Value per share - Authorized 4,000,000 shares							
Series	**Call Price December 31, 2004** (a)	**Number of Shares Redeemed Year Ended December 31,**			**Shares Outstanding December 31, 2004**		
		2004	**2003**	**2002**			
Not Subject to Mandatory Redemption - $100 Par:							
4.08%	$103.0	-	-	-	14,595	$ 1,460	$ 1,460
4.20%	103.2	-	-	-	22,824	2,282	2,282
4.40%	104.0	-	-	-	31,512	3,151	3,151
4.50%	110.0	41	23	-	97,482	9,748	9,752
Total						$ 16,641	$ 16,645
Subject to Mandatory Redemption - $100 Par:							
5.90%	$100.0	22,500	-	-	50,000 (b)	$ 5,000	$ 7,250

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.

(b) All outstanding shares were redeemed on January 3, 2005.

See Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED

SCHEDULE OF CONSOLDIATED LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ -	$ 9,950
Installment Purchase Contracts	490,028	539,406
Senior Unsecured Notes	983,008	1,343,706
Notes Payable - Affiliated	400,000	-
Notes Payable - Nonaffiliated	138,024	146,878
Less Portion Due Within One Year	(12,354)	(431,854)
Long-term Debt Excluding Portion Due Within One Year	$ 1,998,706	$ 1,608,086

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

		2004	2003
% Rate	**Due**	**(in thousands)**	
7.30	2024 - April 1	$ -	$ 10,000
Unamortized Discount		-	(50)
Total		$ -	$ 9,950

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

			2004	2003
	% Rate	**Due**	**(in thousands)**	
Mason County, West Virginia	5.4500	2016 - December 1	$ 50,000	$ 50,000
Marshall County, West Virginia	5.4500	2014 - July 1	50,000	50,000
	5.9000	2022 - April 1	35,000	35,000
	6.8500	2022 - June 1	-	50,000
	(a)	2022 - June 1	50,000	50,000
Ohio Air Quality Development Authority	5.1500	2026 - May 1	50,000	50,000
	5.5625	2022 - October 1	19,565	19,565
	5.5625	2023 - January 1	19,565	19,565
	(b)	2028 - April 1	40,000	40,000
	(c)	2028 - April 1	40,000	40,000
	6.3750	2029 - January 1 (d)	51,000	51,000

6.3750	2029 - April 1 (d)	51,000	51,000
(b)	2029 - April 1	18,000	18,000
(c)	2029 - April 1	18,000	18,000
Unamortized Discount		(2,102)	(2,724)
Total		$ 490,028	$ 539,406

(a) A floating interest rate is determined daily. The rate was 2.19% and 1.29% on December 31, 2004 and 2003, respectively.

(b) A floating interest rate is determined weekly. The rate was 2.10% and 1.13% on December 31, 2004 and 2003, respectively. These bonds will be redeemed in March 2005 with proceeds from an issuance in January 2005.

(c) A floating interest rate is determined weekly. The rate was 2.10% and 1.20% on December 31, 2004 and 2003, respectively. These bonds will be redeemed in March 2005 with proceeds from an issuance in January 2005.

(d) These bonds were redeemed in February 2005 with proceeds from an issuance in January 2005.

Under the terms of the installment purchase contracts, OPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Senior Unsecured Notes outstanding were as follows:

		2004	**2003**
% Rate	**Due**	**(in thousands)**	
6.750	2004 - July 1	$ -	$ 100,000
7.000	2004 - July 1	-	75,000
6.730	2004 - November 1	-	48,000
6.240	2008 - December 4	37,225	37,225
7.375	2038 - June 30	-	140,000
5.500	2013 - February 15	250,000	250,000
4.850	2014 - January 15	225,000	225,000
6.600	2033 - February 15	250,000	250,000
6.375	2033 - July 15	225,000	225,000
Unamortized Discount		(4,217)	(6,519)
Total		$ 983,008	$ 1,343,706

Notes Payable to Parent were as follows:

		2004	**2003**
% Rate	**Due**	**(in thousands)**	
3.32	2006 - May 15	$ 200,000	$ -
5.25	2015 - June 1	200,000	-
Total		$ 400,000	$ -

Notes Payable to third parties outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.810	2008 - March 31	$ 19,024	$ 24,878
6.270	2009 - March 31	38,000	41,000
7.490	2009 - April 15	70,000	70,000
7.210	2009 - June 15	11,000	11,000
Total		$ 138,024	$ 146,878

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ 12,354
2006	212,354
2007	17,853
2008	55,188
2009	77,500
Later Years	1,642,130
Total Principal Amount	2,017,379
Unamortized Discount	(6,319)
Total	$ 2,011,060

OHIO POWER COMPANY CONSOLIDATED

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCos financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company Consolidated as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, and EITF 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003; FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003; and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,047,521	$ 1,102,822	$ 793,647	$ 957,000	$ 956,398
Operating Income	75,076	92,863	84,721	96,988	96,669
Interest Charges	37,957	44,784	40,422	39,249	38,980
Net Income	37,542	53,891	41,060	57,759	66,663
BALANCE SHEETS DATA					
Electric Utility Plant	$ 2,871,016	$ 2,813,681	$ 2,766,328	$ 2,695,099	$ 2,604,670
Accumulated Depreciation and Amortization	1,117,113	1,069,216	1,037,222	989,426	963,176
Net Electric Utility Plant	$ 1,753,903	$ 1,744,465	$ 1,729,106	$ 1,705,673	$ 1,641,494
Total Assets	$ 2,068,818	$ 1,977,317	$ 1,986,147	$ 1,943,928	$ 2,325,500
Common Shareholder's Equity	529,256	483,008	399,247	480,240	474,934
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,267	5,267	5,267	5,267
Trust Preferred Securities (a)	-	-	75,000	75,000	75,000
Long-term Debt (b)	546,092	574,298	545,437	451,129	470,822
Obligations Under Capital Leases (b)	1,284	1,010	-	-	-

(a) See Trust Preferred Securities section of Note 16.

(b) Including portion due within one year.

PUBLIC SERVICE COMPANY OF OKLAHOMA

MANAGEMENTS NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Public Service Company of Oklahoma (PSO) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 509,000 retail customers in eastern and southwestern Oklahoma. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pools sales to neighboring utilities and power marketers. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

2004 Compared to 2003

Net Income decreased $16 million from the prior year primarily due to increased operations and maintenance expenses for power plant maintenance and transmission and distribution expenses.

Fluctuations occurring in the retail portion of fuel and purchased power expense generally do not impact operating income, as they are offset in revenues due to the functioning of the fuel clause adjustment in Oklahoma.

Operating Income

Operating Income for the year decreased $18 million primarily due to:

- A $24 million increase in Other Operation expenses. Transmission expense increased $11 million primarily related to prior years true-up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003. Distribution expenses increased $7 million resulting mainly from a labor settlement and various inventory and tracking system upgrades. General and Administrative expense increased $8 million primarily due to outside services, mostly legal, and pension expense partially offset by the Medicare subsidy.
- A $10 million increase in Maintenance expenses primarily due to increased power plant maintenance and increased storm damage costs.
- A $4 million decrease in transmission revenues primarily due to a 2003 adjustment of nonaffiliated transactions.
- A $6 million increase in Taxes Other Than Income Taxes primarily due to increased property taxes of $4 million attributable to changes in property values. Also, state and local franchise taxes increased $2 million primarily due to a true-up of prior years recorded in 2003.
- A $3 million increase in Depreciation and Amortization expense primarily due to increases in depreciable plant.
- A $3 million decrease in miscellaneous revenue categories due to items such as reduced rental revenues, reduced miscellaneous service charges, and reduced wholesale base revenues as a result of the loss of one customer.

The decrease was partially offset by:

- A $28 million decrease in Income Taxes. See Income Taxes section below for further discussion.

- A $7 million increase in off-system sales margins primarily due to the end of merger related mitigation sales losses in 2003.

Fuel and Purchased Power

Fuel expense decreased 18% due to lower KWH generated of 16%, offset by slightly higher cost per KWH of 3%. In addition, Fuel expenses were affected by a decrease in deferred fuel expense of $28 million. Purchased Power expense increased 26% due to a 15% increase of KWH purchased and higher cost per KWH of 18%.

Other Impacts on Earnings

Nonoperating Income decreased $7 million compared to the prior year period in large part due to a gain on the disposition of land recorded in 2003.

Nonoperating Income Tax Expense (Credit) decreased $2 million also due to the gain mentioned above. See Income Taxes section below for further discussion.

Interest Charges decreased $7 million compared to the prior year due the retirement of higher rate First Mortgage Bonds replaced by lower rate Senior Unsecured Notes and the retirement of $77 million of Trust Preferred Securities.

Income Taxes

The effective tax rates for 2004 and 2003 were 17.2% and 41.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is due primarily to an increase in favorable federal income tax adjustments and a decrease in state income taxes.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moodys	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

In July 2004, Standard and Poors upgraded the credit rating of our First Mortgage Bonds from BBB to A- due to a change in rating methodology. The principal amount of First Mortgage Bonds currently outstanding is $50 million.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ 50.0	$ 50.0	$ 50.0	$ 396.4	$ 546.4
Advances from Affiliates (b)	55.0	-	-	-	55.0
Capital Lease Obligations (c)	0.6	0.6	0.1	0.1	1.4
Noncancelable Operating Leases (c)	5.8	9.3	4.5	6.7	26.3
Fuel Purchase Contracts (d)	251.3	159.8	56.9	82.1	550.1
Energy and Capacity Purchase Contracts (e)	49.4	99.3	90.1	208.6	447.4
Total	$ 412.1	$ 319.0	$ 201.6	$ 693.9	$ 1,626.6

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.

(b) Represents short-term borrowings from the Utility Money Pool.
(c) See Note 15.
(d) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(e) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$14,057
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(1,007)
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(187)
Change in Fair Value Due to Valuation Methodology Changes (d)	-
Changes in Fair Value of Risk Management Contracts (e)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	1,908
Total MTM Risk Management Contract Net Assets	14,771
Net Cash Flow Hedge Contracts (g)	(66)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$14,705

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) Net Cash Flow Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 15,389	$ 5,999	$ 21,388
Noncurrent Assets	14,470	7	14,477
Total MTM Derivative Contract Assets	29,859	6,006	35,865
Current Liabilities	(8,034)	(5,671)	(13,705)
Noncurrent Liabilities	(7,054)	(401)	(7,455)
Total MTM Derivative Contract Liabilities	(15,088)	(6,072)	(21,160)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 14,771	$ (66)	$ 14,705

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)

Prices Actively Quoted - Exchange Traded Contracts	$ (1,949)	$ (70)	$ 980	$ -	$ -	$ -	$ (1,039)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	9,639	2,835	2,442	1,189	-	-	16,105
Prices Based on Models and Other Valuation Methods (b)	(335)	(1,764)	(1,853)	425	1,313	1,919	(295)
Total	$ 7,355	$ 1,001	$ 1,569	$ 1,614	$ 1,313	$ 1,919	$ 14,771

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2004

(in thousands)

	Power	**Interest Rate**	**Total**
Beginning Balance December 31, 2003	$ 156	$ -	$ 156
Changes in Fair Value (a)	1,313	(600)	713
Reclassifications from AOCI to Net Income (b)	(469)	-	(469)
Ending Balance December 31, 2004	$ 1,000	$ (600)	$ 400

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,182 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				December 31, 2003			
(in thousands)				(in thousands)			
End	High	Average	Low	End	High	Average	Low
$238	$778	$335	$115	$258	$1,004	$420	$100

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $35 million and $66 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,036,831	$ 1,079,692	$ 784,208
Sales to AEP Affiliates	10,690	23,130	9,439
TOTAL	1,047,521	1,102,822	793,647
OPERATING EXPENSES			
Fuel for Electric Generation	434,396	526,563	246,199
Purchased Energy for Resale	79,612	35,685	47,507
Purchased Electricity from AEP Affiliates	104,001	109,639	89,454
Other Operation	153,489	129,246	133,538
Maintenance	63,529	53,076	48,060
Depreciation and Amortization	89,711	86,455	85,896
Taxes Other Than Income Taxes	38,587	32,287	34,077
Income Taxes	9,120	37,008	24,195
TOTAL	972,445	1,009,959	708,926
OPERATING INCOME	75,076	92,863	84,721
Nonoperating Income	1,296	8,026	1,920
Nonoperating Expenses	2,184	1,385	6,971
Nonoperating Income Tax Expense (Credit)	(1,311)	829	(1,812)
Interest Charges	37,957	44,784	40,422
NET INCOME	37,542	53,891	41,060
Gain on Reacquired Preferred Stock	2	-	1
Preferred Stock Dividend Requirements	213	213	213
EARNINGS APPLICABLE TO COMMON STOCK	$ 37,331	$ 53,678	$ 40,848

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 157,230	$ 180,016	$ 142,994	$ -	$ 480,240
Gain on Reacquired Preferred Stock			1		1
Common Stock Dividends			(67,368)		(67,368)
Preferred Stock Dividends			(213)		(213)
TOTAL					412,660
COMPREHENSIVE LOSS					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $22				(42)	(42)
Minimum Pension Liability, Net of Tax of $29,309				(54,431)	(54,431)
NET INCOME			41,060		41,060
TOTAL COMPREHENSIVE LOSS					(13,413)
DECEMBER 31, 2002	157,230	180,016	116,474	(54,473)	399,247
Capital Contribution from Parent Company		50,000			50,000
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(213)		(213)
Distribution of Investment in AEMT, Inc.			(548)		(548)
Preferred Shares to Parent Company					
TOTAL					418,486
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $106				198	198
Minimum Pension Liability, Net of Tax of $5,649				10,433	10,433
NET INCOME			53,891		53,891
TOTAL COMPREHENSIVE INCOME					64,522
DECEMBER 31, 2003	157,230	230,016	139,604	(43,842)	483,008
Gain on Reacquired Preferred Stock			2		2
Common Stock Dividends			(35,000)		(35,000)
Preferred Stock Dividends			(213)		(213)
TOTAL					447,797
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					

Cash Flow Hedges, Net of Tax of $131				244	244
Minimum Pension Liability, Net of Tax of $23,516				43,673	43,673
NET INCOME			37,542		37,542
TOTAL COMPREHENSIVE INCOME					81,459
DECEMBER 31, 2004	$ 157,230	$ 230,016	$ 141,935	$ 75	$ 529,256

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA

BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

	2004	2003
ELECTRIC UTILITY PLANT	(in thousands)	
Production	$ 1,072,022	$ 1,065,408
Transmission	468,735	458,577
Distribution	1,089,187	1,031,229
General	200,044	203,756
Construction Work in Progress	41,028	54,711
Total	2,871,016	2,813,681
Accumulated Depreciation and Amortization	1,117,113	1,069,216
TOTAL - NET	1,753,903	1,744,465
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,401	4,631
Other Investments	81	2,320
TOTAL	4,482	6,951
CURRENT ASSETS		
Cash and Cash Equivalents	91	3,738
Other Cash Deposits	188	10,520
Accounts Receivable:		
Customers	34,002	28,515
Affiliated Companies	46,399	19,852
Miscellaneous	6,984	-
Allowance for Uncollectible Accounts	(76)	(37)
Fuel Inventory	14,268	18,331
Materials and Supplies	35,485	38,118
Risk Management Assets	21,388	18,586
Regulatory Asset for Under-Recovered Fuel Costs	366	24,170
Margin Deposits	2,881	4,351
Prepayments and Other	1,378	2,655
TOTAL	163,354	168,799
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	14,705	14,357
Other	17,246	14,342
Long-term Risk Management Assets	14,477	10,379
Prepaid Pension Obligations	82,419	-
Deferred Charges and Other Assets	18,232	18,024
TOTAL	147,079	57,102
TOTAL ASSETS	$ 2,068,818	$ 1,977,317

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - $15 Par Value Per Share:	$ 157,230	$ 157,230
Authorized - 11,000,000 Shares		
Issued - 10,482,000 Shares		
Outstanding - 9,013,000 Shares		
Paid-in Capital	230,016	230,016
Retained Earnings	141,935	139,604
Accumulated Other Comprehensive Income (Loss)	75	(43,842)
Total Common Shareholders Equity	529,256	483,008
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,267
Total Shareholders Equity	534,518	488,275
Long-term Debt:		
Nonaffiliated	446,092	490,598
Affiliated	50,000	-
Total Long-term Debt	496,092	490,598
TOTAL	1,030,610	978,873
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	50,000	83,700
Advances from Affiliates	55,002	32,864
Accounts Payable:		
General	71,442	48,808
Affiliated Companies	58,632	57,206
Customer Deposits	33,757	26,547
Taxes Accrued	18,835	27,157
Interest Accrued	4,023	3,706
Risk Management Liabilities	13,705	11,067
Obligations Under Capital Leases	537	452
Other	30,477	35,234
TOTAL	336,410	326,741
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	384,090	335,434
Long-term Risk Management Liabilities	7,455	3,602
Regulatory Liabilities:		
Asset Removal Costs	220,298	214,033
Deferred Investment Tax Credits	28,620	30,411
SFAS 109 Regulatory Liability, Net	21,963	24,937
Other	19,676	15,406
Obligations Under Capital Leases	747	558
Deferred Credits and Other	18,949	47,322
TOTAL	701,798	671,703
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,068,818	$ 1,977,317

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 37,542	$ 53,891	$ 41,060
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	89,711	86,455	85,896
Deferred Income Taxes	22,034	(14,641)	75,659
Deferred Investment Tax Credits	(1,791)	(1,791)	(1,791)
Mark-to-Market of Risk Management Contracts	(714)	(10,511)	(1,111)
Fuel Recovery	23,804	52,300	(85,190)
Pension Contribution	(48,701)	(88)	-
Change in Other Noncurrent Assets	(26,325)	(9,646)	3,273
Change in Other Noncurrent Liabilities	26,113	16,862	(20,097)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(38,979)	(2,588)	(3,737)
Fuel, Materials and Supplies	6,696	899	996
Accounts Payable	24,060	(33,231)	25,629
Taxes Accrued	(8,322)	20,303	(11,296)
Customer Deposits	7,210	4,758	748
Interest Accrued	317	(3,273)	(319)
Other Current Assets	2,746	(4,271)	(366)
Other Current Liabilities	(4,670)	10,729	12,740
Net Cash Flows From Operating Activities	110,731	166,157	122,094
INVESTING ACTIVITIES			
Construction Expenditures	(82,326)	(86,815)	(89,365)
Change in Other Cash Deposits, Net	10,332	(3,289)	(4,284)
Proceeds from Sale of Assets	458	2,862	-
Other	-	-	963
Net Cash Flows Used For Investing Activities	(71,536)	(87,242)	(92,686)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	-	50,000	-
Issuance of Long-term Debt - Nonaffiliated	82,255	148,734	-
Issuance of Long-term Debt - Affiliated	50,000	-	187,850
Retirement of Long-term Debt - Nonaffiliated	(162,020)	(200,000)	(106,000)
Retirement of Cumulative Preferred Stock	(2)	-	-
Change in Advances to/from Affiliates, Net	22,138	(53,241)	(36,982)
Dividends Paid on Common Stock	(35,000)	(30,000)	(67,368)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows Used For Financing Activities	(42,842)	(84,720)	(22,713)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,647)	(5,805)	6,695
Cash and Cash Equivalents at Beginning of Period	3,738	9,543	2,848
Cash and Cash Equivalents at End of Period	$ 91	$ 3,738	$ 9,543

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $32,961,000, $44,703,000 and $38,620,000 and for income taxes was $2,387,000, $36,470,000 and $(38,943,000) in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $796,000. There was a noncash distribution of $548,000 in preferred shares in AEMT, Inc. to PSOs Parent Company in 2003.

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

						2004	2003
						(in thousands)	
PREFERRED STOCK:							
Cumulative $100 par value per share - authorized shares 700,000, redeemable at our option upon 30 days notice.							
Series	**Call Price December 31, 2004**	**Number of Shares Redeemed Year Ended December 31, 2004**	**2003**	**2002**	**Shares Outstanding December 31, 2004**		
Not subject to Mandatory Redemption:							
4.00%	$105.75	50	2	6	44,548	$ 4,455	$ 4,460
4.24%	103.19	-	-	1	8,069	807	807
Total						$ 5,262	$ 5,267

See Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA

SCHEDULE OF LONG-TERM DEBT

December 31, 2004 and 2003

(in thousands)

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
First Mortgage Bonds	$ 49,970	$ 99,864
Installment Purchase Contracts	46,360	47,358
Senior Unsecured Notes	399,762	349,756
Notes Payable to Trust (a)	-	77,320
Notes Payable - Affiliated	50,000	-
Less Portion Due Within One Year	(50,000)	(83,700)
Long-term Debt Excluding Portion Due Within One Year	$ 496,092	$ 490,598

(a) See Trust Preferred Securities section of Note 16 for discussion of Notes Payable to Trust.

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of our affiliates.

First Mortgage Bonds outstanding were as follows :

% Rate	Due	2004	2003
		(in thousands)	
7.375	2004 - December 1	$ -	$ 50,000
6.500	2005 - June 1	50,000	50,000
Unamortized Discount		(30)	(136)
Total		$ 49,970	$ 99,864

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Oklahoma EnvironmentalFinance Authority (OEFA)	5.900	2007 - December 1	$ -	$ 1,000
Oklahoma DevelopmentFinance Authority (ODFA)	4.875	2014 - June 1	-	33,700
	Variable	2014 - June 1 (a)	33,700	-
Red River Authority of Texas	6.000	2020 - June 1	12,660	12,660
	Unamortized Discount		-	(2)
	Total		$ 46,360	$ 47,358

(a) The interest rate on December 31, 2004 was 1.750%.

Under the terms of the installment purchase contracts, PSO is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
4.700	2009 - June 15	$ 50,000	$ -
4.850	2010 - September 15	150,000	150,000
6.000	2032 - December 31	200,000	200,000
Unamortized Discount		(238)	(244)
Total		$ 399,762	$ 349,756

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2004	2003
		(in thousands)	
8.000	2037 - April 30	$ -	$ 77,320

See Trust Preferred Securities section of Note 16 for discussion of Notes Payable to Trust.

Notes Payable to parent company was as follows:

		2004	2003
% Rate	**Due**	**(in thousands)**	
3.350	2006 - May 15	$ 50,000	$ -

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount (in thousands)
2005	$ 50,000
2006	50,000
2007	-
2008	-
2009	50,000
Later Years	396,360
Total Principal Amount	546,360
Unamortized Discount	(268)
Total	$ 546,092

PUBLIC SERVICE COMPANY OF OKLAHOMA

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSOs financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Public Service Company of Oklahoma:

We have audited the accompanying balance sheets of Public Service Company of Oklahoma as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003 and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 1,087,346	$ 1,146,842	$ 1,084,720	$ 1,101,326	$ 1,118,274
Operating Income	143,178	150,136	142,469	146,207	128,278
Interest Charges	53,529	63,779	59,168	57,581	59,457
Income Before Cumulative Effect of Accounting Changes	89,457	89,624	82,992	89,367	72,672
Cumulative Effect of Accounting Changes, Net of Tax	-	8,517	-	-	-
Net Income	89,457	98,141	82,992	89,367	72,672
BALANCE SHEETS DATA					
Electric Utility Plant	$ 3,887,367	$ 3,799,460	$ 3,596,174	$ 3,460,764	$ 3,319,024
Accumulated Depreciation and Amortization	1,709,758	1,617,846	1,477,875	1,342,003	1,259,509
Net Electric Utility Plant	$ 2,177,609	$ 2,181,614	$ 2,118,299	$ 2,118,761	$ 2,059,515
Total Assets	$ 2,646,309	$ 2,581,963	$ 2,428,138	$ 2,509,291	$ 2,855,885
Common Shareholder's Equity	768,618	696,660	661,769	689,578	674,652
Cumulative Preferred Stock NotSubject to Mandatory Redemption	4,700	4,700	4,701	4,701	4,701
Trust Preferred Securities (a)	-	-	110,000	110,000	110,000
Long-term Debt (b)	805,369	884,308	693,448	645,283	645,963
Obligations Under Capital Leases (b)	34,546	21,542	-	-	-

(a) See Trust Preferred Securities section of Note 16.

(b) Including portion due within one year.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS

Southwestern Electric Power Company (SWEPCo) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 444,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. We consolidate Southwest Arkansas Utilities Corporation and Dolet Hills Lignite Company, LLC, our wholly-owned subsidiaries. We also consolidate Sabine Mining Company, a variable interest entity. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pools sales to neighboring utilities and power marketers. We also sell electric power at wholesale to other utilities, municipalities and electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income decreased $9 million for 2004. The decrease is primarily due to the $9 million (net of tax) Cumulative Effect of Accounting Changes recorded in 2003.

Net Income increased $15 million for 2003 primarily due to an $8 million increase in Operating Income and the adoption of SFAS 143, which resulted in Cumulative Effect of Accounting Changes of $9 million in the first quarter of 2003. Significant fluctuations occurred in revenues, fuel and purchased power due to certain Interchange Cost Reconstruction (ICR) adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Fluctuations occurring in the retail portion of fuel and purchased power expense, except for capacity related items, generally do not impact operating income, as they are offset in revenues and/or operations expense due to the functioning of the fuel adjustment clauses in the states in which we serve.

2004 Compared to 2003

Operating Income

Operating Income decreased by $7 million primarily due to:

- A $14 million increase in Other Operation expenses primarily related to a prior year true-up for OATT transmission recorded in 2004 resulting from revised data from ERCOT for the years 2001-2003 offset in part by the sale of emission allowances.
- A $10 million increase in Taxes Other Than Income Taxes primarily due to higher franchise taxes of $8 million resulting from a true-up of prior years recorded in 2003 and higher property related taxes.
- An $8 million increase in Depreciation and Amortization expenses primarily due to the amortization of a regulatory asset for the recovery of fuel related costs in Arkansas established in 2003 by a credit to amortization and adjustments to excess earnings accruals per the Texas Restructuring Legislation (see Texas Restructuring and Unrefunded Excess Earnings in Note 6). Also, depreciation increased due to increases in depreciable plant.
- A $5 million decrease in margins from risk management activities.
- A $4 million increase in Maintenance expenses primarily due to scheduled power plant maintenance, as well as increased overhead line maintenance.
- A $4 million decrease in the portion of margin the company retains from off-system sales primarily due to decreased realization on off-system sales.
- A $2 million decrease in retail base revenues due to a decline of 5% in heating and cooling degree-days.

The decrease in Operating Income was partially offset by:

- An $18 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $2 million decrease in provision for rate refund primarily due to a wholesale fuel refund in 2003.

Fuel and Purchased Power

Fuel expense decreased 12% primarily due to lower KWH generation of 2% and lower cost per KWH of 8%. Purchased power expense decreased 22% in large part due to decreased capacity purchases reflecting a $9 million refund received for prior year purchased capacity amounts. Capacity related transactions are not included in the fuel adjustment clauses, and therefore, changes impact operating income.

Other Impacts on Earnings

Interest Charges decreased $10 million as a result of refinancing higher interest rate debt with lower interest rate debt.

The increase in Minority Interest expense of $2 million is a result of consolidating Sabine Mining Company (Sabine), effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabines revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement lines were affected.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to a one-time after tax impact of adopting SFAS 143 and EITF 02-3 in 2003 (see Note 2).

Income Taxes

The effective tax rates for 2004 and 2003 were 28% and 36.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to federal income tax adjustments, a decrease in state income taxes and permanent differences relating primarily to a Medicare subsidy credit.

2003 Compared to 2002

Operating Income

Operating Income increased by $8 million primarily due to:

A $12 million increase in retail base revenues due to increased customers and their average usage, offset in part by milder weather. Heating cooling degree-days declined 6%.

A $12 million increase in wholesale margins due to an increase in our allocation of overall AEP off-system sales percentages resulting from increased amounts of off-system sales.
An $11 million decrease in Other Operation expenses primarily due to decreases in customer services, outside services and other administrative expenses.
A $7 million increase in income from risk management activities.

The increase in Operating Income was partially offset by:

A $21 million increase in Income Taxes. See Income Taxes section below for further discussion.

A $9 million decrease in wholesale base margins primarily due to decreased demand from wholesale customers.
A $4 million decrease in capacity revenues due to the elimination of the requirement under the Texas Restructuring Legislation to sell capacity (see Note 6).

Other Impacts on Earnings

Nonoperating Income Tax Expense (Credit) increased by $5 million due to changes in certain book/tax timing differences accounted for on a flow-through basis, changes in consolidated tax savings and tax return and tax accrual adjustments.

Interest Charges increased $5 million primarily due to higher levels of outstanding debt, consolidation of Sabine and increased financing activity at Dolet Hills.

The increase in Minority Interest expense of $2 million is a result of consolidating Sabine effective July 1, 2003, due to implementation of FIN 46. We now record the depreciation, interest and other operating expenses of Sabine and eliminate Sabines revenues against our fuel expenses. While there was no effect to net income as a result of consolidation, some individual income statement lines were affected.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 in 2003 (see Note 2).

Income Taxes

The effective tax rates for 2003 and 2002 were 36.3% and 29.9%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to an increase in state income taxes and permanent differences relating primarily to book depletion.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moodys	**S&P**	**Fitch**
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

In July 2004, Standard and Poors upgraded the credit rating of the First Mortgage Bonds from BBB to A- due to a change in rating methodology. The principal amount of First Mortgage Bonds currently outstanding is $96 million.

Cash Flow

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	2004	**2003**	**2002**
		(in thousands)	
Cash and cash equivalents at beginning of period	$ 5,676	$ -	$ 5,023
Cash flows from (used for):			
Operating activities	209,734	248,094	210,563
Investing activities	(97,933)	(114,828)	(112,318)
Financing activities	(115,169)	(127,590)	(103,268)
Net increase (decrease) in cash and cash equivalents	(3,368)	5,676	(5,023)
Cash and cash equivalents at end of period	$ 2,308	$ 5,676	$ -

Operating Activities

Our net cash flows from operating activities were $210 million in 2004. We produced income of $89 million during the period and noncash expense items of $129 million for Depreciation and Amortization. Change in Pension Contribution of $46 million is due to the pension plan funding. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Receivable, Net, Fuel, Materials and Supplies and Taxes Accrued. Accounts Receivable, Net increased related to increased affiliated energy purchases. The decrease in Fuel, Materials and Supplies is primarily due to lower purchases of fuel. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP Consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments. Payment will be made in March 2005 when the 2004 federal income tax return extension is filed.

Our net cash flows from operating activities were $248 million in 2003. We produced income of $98 million during the period and noncash expense items of $121 million for Depreciation and Amortization and $9 million for Cumulative Effect of Accounting Changes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant were Accounts Receivable, Net and Accounts Payable. Accounts Receivable, Net decreased primarily due to prior year adjustments to the interchange cost reconstruction system and lower affiliated energy purchases. The decrease in Accounts Payable was related to lower fuel purchases.

Our net cash flows from operating activities were $211 million in 2002. We produced income of $83 million during the period and noncash expense items of $123 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant were Accounts Receivable, Net, Fuel, Materials and Supplies and Taxes Accrued. Accounts Receivable, Net decreased primarily due to an adjustment to the interchange cost reconstruction system. Fuel, Materials and Supplies increased due to higher coal purchases. Taxes accrued increased due to higher income taxes offset in part by state and local franchise taxes.

Investing Activities

Cash flows used for investing activities during 2004, 2003 and 2002 were $98 million, $115 million and $112 million, respectively. They were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash flows used for financing activities were $115 million during 2004. During the first and second quarter, we retired $80 million and $40 million of First Mortgage Bonds, respectively. Three Installment Purchase Contracts were retired for Titus County with fixed interest rates in the second quarter totaling $41 million which were replaced by one Installment Purchase Contract with a variable interest rate for $41 million. During the third quarter of 2004, we issued a Note Payable to AEP for $50 million. Common Stock Dividends were $60 million.

Cash flows used for financing activities were $128 million during 2003. During the first quarter of 2003, we retired $55 million of First Mortgage Bonds at maturity. In April 2003, we issued $100 million of Senior Unsecured Notes due 2015 at a coupon of 5.375%. In May 2003, one of our mining subsidiaries issued $44 million of notes due in 2011 at a coupon of 4.47%. The loan was used primarily to reduce a note to us with an interest rate of 8.06%. During the fourth quarter of 2003, we had an early redemption of $45 million of First Mortgage Bonds due in 2023. Common Stock dividends were $73 million.

Cash flows used for financing activities were $103 million for 2002. During the first quarter of 2002, we retired Senior Unsecured Notes of $150 million. We issued $200 million of Senior Unsecured Notes in the second quarter of 2002. Common stock dividends were $57 million.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period

(in millions)

Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt (a)	$ 210.0	$ 118.1	$ 11.0	$ 465.6	$ 804.7
Capital Lease Obligations (b)	6.2	11.9	11.3	20.5	49.9
Noncancelable Operating Leases (b)	6.8	14.8	17.1	10.6	49.3
Fuel Purchase Contracts (c)	198.4	355.7	232.8	472.3	1,259.2
Energy and Capacity Purchase Contracts (d)	27.9	56.1	50.9	117.9	252.8
Total	$ 449.3	$ 556.6	$ 323.1	$ 1,086.9	$ 2,415.9

(a) See Schedule of Consolidated Long-term Debt. Represents principal only excluding interest.

(b) See Note 15.
(c) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. Our commitments outstanding at December 31, 2004 under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

(in millons)

Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Standby Letters of Credit (a)	$ 4.0	$ -	$ -	$ -	$ 4.0
Guarantees of the Performance of Outside Parties (b)	10.5	-	22.0	105.0	137.5
Total	$ 14.5	$ -	$ 22.0	$ 105.0	$ 141.5

(a) We have issued standby letters of credit to third parties. These letters of credit cover insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in our ordinary course of business. The maximum future payments of these letters of credit are $4.0 million maturing in December 2005. There is no recourse to third parties in the event these letters of credit are drawn.

(b) See Note 8.

Other

On July 1, 2003, we consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, we recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, we currently record all expenses (depreciation, interest and other operation expense) of Sabine and eliminate Sabines revenues against our fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Significant Factors

See the Combined Managements Discussion and Analysis of Registrant Subsidiaries section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See Critical Accounting Estimates section in Combined Managements Discussion and Analysis of Registrant Subsidiaries for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEPs Quantitative and Qualitative Disclosures About Risk Management Activities section. The following tables provide information about AEPs risk management activities effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets

Year Ended December 31, 2004

(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$16,606
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(4,481)
Fair Value of New Contracts When Entered During the Period (b)	743
Net Option Premiums Paid/(Received) (c)	(221)
Change in Fair Value Due to Valuation Methodology Changes (d)	62
Changes in Fair Value of Risk Management Contracts (e)	3,008
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	1,810
Total MTM Risk Management Contract Net Assets	17,527
Net Cash Flow Hedge Contracts (g)	(2,704)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$14,823

(a) (Gain) Loss from Contracts Realized/Settled During the Period includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.

(b) Fair Value of New Contracts When Entered During the Period represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) Net Option Premiums Paid/(Received) reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.

(d) Change in Fair Value Due to Valuation Methodology Changes represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.

(e) Changes in Fair Value of Risk Management Contracts represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) Net Cash Flow Hedge Contracts (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Consolidated Balance Sheets

As of December 31, 2004

(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 18,260	$ 7,119	$ 25,379
Noncurrent Assets	17,170	9	17,179
Total MTM Derivative Contract Assets	35,430	7,128	42,558
Current Liabilities	(9,533)	(9,074)	(18,607)
Noncurrent Liabilities	(8,370)	(758)	(9,128)
Total MTM Derivative Contract Liabilities	(17,903)	(9,832)	(27,735)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 17,527	$ (2,704)	$ 14,823

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).

The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM

Risk Management Contract Net Assets

Fair Value of Contracts as of December 31, 2004

(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)

Prices Actively Quoted - Exchange Traded Contracts	$ (2,313)	$ (84)	$ 1,163	$ -	$ -	$ -	$ (1,234)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	11,438	3,364	2,898	1,411	-	-	19,111
Prices Based on Models and Other Valuation Methods (b)	(398)	(2,092)	(2,199)	504	1,558	2,277	(350)
Total	$ 8,727	$ 1,188	$ 1,862	$ 1,915	$ 1,558	$ 2,277	$ 17,527

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Years Ended December 31, 2004

(in thousands)

	Power	**Interest Rate**	**Total**
Beginning Balance December 31, 2003	$ 184	$ -	$ 184
Changes in Fair Value (a)	1,558	(2,008)	(450)
Reclassifications from AOCI to Net Income (b)	(554)	-	(554)
Ending Balance December 31, 2004	$ 1,188	$ (2,008)	$ (820)

(a) Changes in Fair Value shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.

(b) Reclassifications from AOCI to Net Income represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,413 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004				**December 31, 2003**			
(in thousands)				**(in thousands)**			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$283	$923	$398	$136	$304	$1,182	$495	$118

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $31 million and $57 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 1,016,156	$ 1,077,988	$ 1,012,391
Sales to AEP Affiliates	71,190	68,854	72,329
TOTAL	1,087,346	1,146,842	1,084,720
OPERATING EXPENSES			
Fuel for Electric Generation	387,554	440,080	391,355
Purchased Energy for Resale	35,521	34,850	44,119
Purchased Electricity from AEP Affiliates	29,054	47,914	42,022
Other Operation	188,601	174,714	186,003
Maintenance	74,091	70,443	66,855
Depreciation and Amortization	129,329	121,072	122,969
Taxes Other Than Income Taxes	63,560	53,165	55,232
Income Taxes	36,458	54,468	33,696
TOTAL	944,168	996,706	942,251
OPERATING INCOME	143,178	150,136	142,469
Nonoperating Income	4,337	3,978	3,260
Nonoperating Expenses	3,030	2,607	1,797
Nonoperating Income Tax Expense (Credit)	(1,731)	(3,396)	1,772
Interest Charges	53,529	63,779	59,168
Minority Interest	(3,230)	(1,500)	-
Income Before Cumulative Effect of Accounting Changes	89,457	89,624	82,992
Cumulative Effect of Accounting Changes, Net of Tax	-	8,517	-
NET INCOME	89,457	98,141	82,992
Preferred Stock Dividend Requirements	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$ 89,228	$ 97,912	$ 82,763

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS

EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 135,660	$ 245,003	$ 308,915	$ -	$ 689,578
Common Stock Dividends			(56,889)		(56,889)
Preferred Stock Dividends			(229)		(229)
TOTAL					632,460
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $26				(48)	(48)
Minimum Pension Liability, Net of Taxof $28,880				(53,635)	(53,635)
NET INCOME			82,992		82,992
TOTAL COMPREHENSIVE INCOME					29,309
DECEMBER 31, 2002	135,660	245,003	334,789	(53,683)	661,769
Common Stock Dividends			(72,794)		(72,794)
Preferred Stock Dividends			(229)		(229)
TOTAL					588,746
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $125				232	232
Minimum Pension Liability, Net of Tax of $5,138				9,541	9,541
NET INCOME			98,141		98,141
TOTAL COMPREHENSIVE INCOME					107,914
DECEMBER 31, 2003	135,660	245,003	359,907	(43,910)	696,660
Common Stock Dividends			(60,000)		(60,000)
Preferred Stock Dividends			(229)		(229)
TOTAL					636,431
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $541				(1,004)	(1,004)
Minimum Pension Liability, Net of Tax of $23,550				43,734	43,734
NET INCOME			89,457		89,457
TOTAL COMPREHENSIVE INCOME					132,187
DECEMBER 31, 2004	$ 135,660	$ 245,003	$ 389,135	$ (1,180)	$ 768,618

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

CONSOLIDATED BALANCE SHEETS

ASSETS

December 31, 2004 and 2003

(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 1,663,161	$ 1,622,498
Transmission	632,964	615,158
Distribution	1,114,480	1,078,368
General	427,910	423,427
Construction Work in Progress	48,852	60,009
Total	3,887,367	3,799,460
Accumulated Depreciation and Amortization	1,709,758	1,617,846
TOTAL - NET	2,177,609	2,181,614
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,049	3,808
Other Investments	4,628	4,710
TOTAL	8,677	8,518
CURRENT ASSETS		
Cash and Cash Equivalents	2,308	5,676
Other Cash Deposits	6,292	6,048
Advances to Affiliates	39,106	66,476
Accounts Receivable:		
Customers	39,042	41,474
Affiliated Companies	28,817	10,394
Miscellaneous	5,856	4,682
Allowance for Uncollectible Accounts	(45)	(2,093)
Fuel Inventory	45,793	63,881
Materials and Supplies	36,051	33,772
Risk Management Assets	25,379	19,715
Regulatory Asset for Under-Recovered Fuel Costs	4,687	11,394
Margin Deposits	3,419	5,123
Prepayments and Other	18,331	19,078
TOTAL	255,036	285,620
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	18,000	3,235
Unamortized Loss on Reacquired Debt	20,765	19,331
Other	16,350	15,859
Long-term Risk Management Assets	17,179	12,178
Prepaid Pension Obligations	81,132	-
Deferred Charges	51,561	55,608
TOTAL	204,987	106,211
TOTAL ASSETS	$ 2,646,309	$ 2,581,963

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholders Equity:		
Common Stock - $18 Par Value per share		
Authorized - 7,600,000 Shares		
Outstanding - 7,536,640 Shares	$ 135,660	$ 135,660
Paid-in Capital	245,003	245,003
Retained Earnings	389,135	359,907
Accumulated Other Comprehensive Loss	(1,180)	(43,910)
Total Common Shareholders Equity	768,618	696,660
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholders Equity	773,318	701,360
Long-term Debt:		
Nonaffiliated	545,395	741,594
Affiliated	50,000	-
Total Long-term Debt	595,395	741,594
TOTAL	1,368,713	1,442,954
Minority Interest	1,125	1,367
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	209,974	142,714
Accounts Payable:		
General	40,001	37,646
Affiliated Companies	33,285	35,138
Customer Deposits	30,550	24,260
Taxes Accrued	45,474	28,691
Interest Accrued	12,509	16,852
Risk Management Liabilities	18,607	11,361
Obligations Under Capital Leases	3,692	3,159
Regulatory Liability for Over-Recovered Fuel	9,891	4,178
Other	33,417	53,753
TOTAL	437,400	357,752
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	399,756	349,064
Long-term Risk Management Liabilities	9,128	4,667
Reclamation Reserve	7,624	16,512
Regulatory Liabilities:		
Asset Removal Costs	249,892	236,409
Deferred Investment Tax Credits	35,539	39,864
Excess Earnings	3,167	2,600
Other	21,320	18,779
Asset Retirement Obligations	27,361	8,429
Obligations Under Capital Leases	30,854	18,383
Deferred Credits and Other	54,430	85,183
TOTAL	839,071	779,890
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,646,309	$ 2,581,963

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 89,457	$ 98,141	$ 82,992
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	129,329	121,072	122,969
Deferred Income Taxes	12,782	9,942	(3,134)
Deferred Investment Tax Credits	(4,326)	(4,326)	(4,524)
Cumulative Effect of Accounting Changes	-	(8,517)	-
Mark-to-Market of Risk Management Contracts	(921)	(12,403)	(1,151)
Fuel Recovery	12,420	(21,577)	17,713
Pension Contribution	(45,688)	(805)	-
Change in Other Noncurrent Assets	(21,251)	22,507	23,570
Change in Other Noncurrent Liabilities	37,014	47,834	(762)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(19,213)	27,527	(24,371)
Fuel, Materials and Supplies	15,809	4,168	(10,541)
Accounts Payable	502	(51,687)	11,633
Taxes Accrued	16,783	8,446	(17,441)
Customer Deposits	6,290	4,150	230
Interest Accrued	(4,343)	(761)	4,024
Other Current Assets	2,452	(6,242)	865
Other Current Liabilities	(17,362)	10,625	8,491
Net Cash Flows From Operating Activities	209,734	248,094	210,563
INVESTING ACTIVITIES			
Construction Expenditures	(103,124)	(121,124)	(111,775)
Change in Other Cash Deposits, Net	(244)	(3,979)	(1,677)
Proceeds from Sale of Assets	5,435	3,800	-
Other	-	6,475	1,134
Net Cash Flows Used For Investing Activities	(97,933)	(114,828)	(112,318)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Nonaffiliated	91,999	254,630	198,573
Issuance of Long-term Debt - Affiliated	50,000	-	-
Retirement of Long-term Debt	(224,309)	(219,482)	(150,595)
Change in Advances to/from Affiliates, Net	27,370	(89,715)	(94,128)
Dividends Paid on Common Stock	(60,000)	(72,794)	(56,889)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows Used For Financing Activities	(115,169)	(127,590)	(103,268)
Net Increase (Decrease) in Cash and Cash Equivalents	(3,368)	5,676	(5,023)
Cash and Cash Equivalents at Beginning of Period	5,676	-	5,023
Cash and Cash Equivalents at End of Period	$ 2,308	$ 5,676	$ -

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $49,739,000, $57,775,000 and $49,008,000 and for income taxes was $11,326,000, $33,616,000 and $60,451,000 in 2004, 2003 and 2002, respectively. Noncash capital lease acquisitions in 2004 were $16,549,000. Noncash activity in 2003 included an increase in assets and liabilities of $78 million resulting from the consolidation of Sabine Mining Company (see Consolidation of Variable Interest Entities section of Note 2).

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SCHEDULE OF PREFERRED STOCK

December 31, 2004 and 2003

						2004	2003
						(in thousands)	
PREFERRED STOCK:							
$100 Par Value per share - Authorized 1,860,000 shares							
	Call Price December 31, 2004	**Number of Shares Redeemed**			**Shares Outstanding**		
Series		**Year Ended December 31,**			**December 31, 2004**		
		2004	**2003**	**2002**			
Not Subject to Mandatory Redemption - $100 Par:							
4.28%	$103.90	-	-	-	7,386	$ 740	$ 740
4.65%	102.75	-	-	-	1,907	190	190
5.00%	109.00	-	12	-	37,703	3,770	3,770
Total						$ 4,700	$ 4,700

See Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT

December 31, 2004 and 2003

	2004	2003
LONG-TERM DEBT:	(in thousands)	
First Mortgage Bonds	$ 96,024	$ 215,712
Installment Purchase Contracts	177,879	178,531
Senior Unsecured Notes	299,686	299,216
Notes Payable to Trust (a)	113,019	113,009
Notes Payable - Nonaffiliated	68,761	77,840
Notes Payable - Affiliated	50,000	-
Less Portion Due Within One Year	(209,974)	(142,714)
Long-term Debt Excluding Portion Due Within One Year	$ 595,395	$ 741,594

(a) See Trust Preferred Securities section of Note 16 for discussion of Notes Payable to Trust.

There are certain limitations on establishing additional liens against our assets under our indenture. None of our long-term debt obligations have been guaranteed or secured by AEP or any of its affiliates.

First Mortgage Bonds outstanding were as follows:

		2004	2003
% Rate	**Due**	(in thousands)	
7.750	2004 - June 1	$ -	$ 40,000
6.200	2006 - November 1	5,215	5,360
6.200	2006 - November 1	1,000	1,000
7.000	2007 - September 1	90,000	90,000
6.875	2025 - October 1	-	80,000
Unamortized Discount		(191)	(648)
Total		$ 96,024	$ 215,712

First Mortgage Bonds are secured by a first mortgage lien on Electric Utility Plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2004	2003
			(in thousands)	
Desoto County	7.600	2019 - January 1	$ -	$ 53,500
	Variable (a)	2019 - January 1	53,500	-
Sabine River Authority of Texas	6.100	2018 - April 1	81,700	81,700
Titus County	Variable (b)	2011 - July 1	41,135	-
	6.900	2004 - November 1	-	12,290
	6.000	2008 - January 1	-	12,170
	8.200	2011 - August 1	-	17,125
	Unamortized Discount		1,544	1,746
	Total		$ 177,879	$ 178,531

(a) The rate on December 31, 2004 was 1.700%.

(b) The rate on December 31, 2004 was 1.850%.

Under the terms of the installment purchase contracts, SWEPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
4.500	2005 - July 1	$ 200,000	$ 200,000
5.375	2015 - April 15	100,000	100,000
Unamortized Discount		(314)	(784)
Total		$ 299,686	$ 299,216

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2004	2003
		(in thousands)	
5.250 (a)	2043 - October 1	$ 113,403	$ 113,403
Unamortized Discount		(384)	(394)
Total		$ 113,019	$ 113,009

(a) The 5.25% interest rate is fixed through September 10, 2008 after which they will become floating rate bonds if the notes are not remarketed.

See Trust Preferred Securities section of Note 16 for discussion of Notes Payable to Trust.

Notes Payable outstanding were as follows:

	% Rate	Due	2004		2003	
			(in thousands)			
Sabine Mining Company (a)	6.360	2007 - February 22	$	4,000	$	4,000
	Variable (b)	2008 - June 30		11,250		13,500
	7.030	2012 - February 22		20,000		20,000
Dolet Hills Lignite Company	4.470	2011 - May 16		33,511		40,340
Total			$	68,761	$	77,840

(a) Sabine Mining Company was consolidated during the third quarter of 2003 due to the implementation of FIN 46.
(b) A floating interest rate is determined quarterly. The rate on December 31, 2004 was 2.325%.

Notes Payable to parent company was as follows:

% Rate	Due	2004		2003	
		(in thousands)			
4.450	2010 - March 15	$	50,000	$	-

At December 31, 2004 future annual long-term debt payments are as follows:

	Amount	
	(in thousands)	
2005	$	209,974
2006		15,754
2007		102,312
2008		5,906
2009		5,156
Later Years		465,612
Total Principal Amount		804,714
Unamortized Discount		655
Total	$	805,369

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCos consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common shareholders equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Companys management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations, effective January 1, 2003; FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003; and FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003, effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio

February 28, 2005

NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements, ExtraordinaryItem and Cumulative Effect of AccountingChanges	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Goodwill and Other Intangible Assets	SWEPCo
4.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Effects of Regulation	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
7.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Sustained Earnings ImprovementInitiative	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Dispositions, Impairments, AssetsHeld for Sale and Assets Heldand Used	APCo, CSPCo, I&M, KPCo, OPCo, TCC, TNC
11.	Benefit Plans	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
13.	Derivatives, Hedging and Financial Instruments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
14.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

15.	Leases	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
16.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
17.	Related Party Transactions	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
18.	Jointly Owned Electric Utility Plant	CSPCo, PSO, SWEPCo, TCC, TNC
19.	Unaudited Quarterly Financial Information	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by AEPs ten domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

With the exception of AEGCo, Registrant Subsidiaries engage in wholesale electricity marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

See Note 10 for additional information regarding asset impairments and assets and liabilities held for sale related to our Texas generation plants.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

AEP and its subsidiaries are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations. Wholesale power markets are generally market-based and are not cost-based regulated unless a generator/seller of wholesale power is determined by the FERC to have market power. The FERC also regulates transmission service and rates particularly in states that have restructured and unbundled their rates. The state commissions regulate all or portions of our retail operations and retail rates dependent on the status of customer choice in each state jurisdiction (see Note 6).

Principles of Consolidation

The consolidated financial statements for APCo, CSPCo, I&M, OPCo, SWEPCo and TCC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities. Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Nonoperating Income. OPCo and SWEPCo also consolidate variable interest entities in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) Consolidation of Variable Interest Entities (FIN 46R) (see Note 2). CSPCo, PSO, SWEPCo, TCC and TNC also have generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the financial statements and the investments are reflected in the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the Registrant Subsidiaries financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, Accounting for the Effects of Certain Types of Regulation, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. The following Registrant Subsidiaries discontinued the application of SFAS 71 for the generation portion of their business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December

2003. During 2003, APCo reapplied SFAS 71 for its West Virginia generation operations and SWEPCo reapplied SFAS 71 for its Arkansas generation operations. SFAS 101, Regulated Enterprises - Accounting for the Discontinuance of Application of FASB Statement No. 71 requires the recognition of an impairment of a regulatory asset arising from the discontinuance of SFAS 71 be classified as an extraordinary item.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, goodwill and intangible asset impairment, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension benefits. The estimates and assumptions used are based upon managements evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the nonregulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are charged to accumulated depreciation. For nonregulated operations, retirements from the plant accounts, net of salvage, are charged to accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses.

The Registrant Subsidiaries implemented SFAS 143 effective January 1, 2003 (see Accounting for Asset Retirement Obligations section of this note).

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets is no longer recoverable or when the assets meet the held for sale criteria under SFAS 144, Accounting for the Impairment or Disposal of Long-lived Assets. Equity investments are required to be tested for impairment when it is determined that an other than temporary loss in value has occurred.

The fair value of an asset and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries for the year 2004:

	Nuclear	**Steam**	**Hydro**	**Transmission**	**Distribution**	**General**
				(in percentages)		
AEGCo	-	3.5	-	-	-	16.4

APCo	-	3.1	2.6	2.2	3.3	9.4
CSPCo	-	2.9	-	2.3	3.6	10.3
I&M	3.1	4.5	3.3	1.9	4.1	11.2
KPCo	-	3.8	-	1.7	3.5	9.2
OPCo	-	2.8	2.7	2.3	4.0	10.1
PSO	-	2.7	-	2.3	3.3	7.9
SWEPCo	-	3.3	-	2.8	3.6	6.9
TCC	-	-	-	2.3	3.4	6.5
TNC	-	2.6	-	3.0	3.2	8.4

The annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries for the year 2003 were as follows:

	Nuclear	**Steam**	**Hydro**	**Transmission**	**Distribution**	**General**
				(in percentages)		
AEGCo	-	3.5	-	-	-	16.7
APCo	-	3.3	2.7	2.2	3.3	9.3
CSPCo	-	3.0	-	2.3	3.6	9.9
I&M	3.4	4.6	3.4	1.9	4.2	11.8
KPCo	-	3.8	-	1.7	3.5	7.1
OPCo	-	2.8	2.7	2.3	4.0	10.5
PSO	-	2.7	-	2.3	3.4	9.7
SWEPCo	-	3.3	-	2.8	3.6	8.0
TCC	2.5	2.3	1.9	2.3	3.5	8.1
TNC	-	2.6	-	3.1	3.3	10.2

The annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries for the year 2002 were as follows:

	Nuclear	**Steam**	**Hydro**	**Transmission**	**Distribution**	**General**
				(in percentages)		
AEGCo	-	3.5	-	-	-	2.8
APCo	-	3.4	2.9	2.2	3.3	3.1
CSPCo	-	3.2	-	2.3	3.6	3.2
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.3
SWEPCo	-	3.4	-	2.7	3.6	4.7
TCC	2.5	2.6	1.9	2.3	3.5	4.0
TNC	-	2.8	-	3.1	3.3	6.8

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs related to SWEPCo were $0.65 per ton in 2004 and $0.41 in 2003 and 2002. In 2004, average amortizations rates increased from 2003 due to a lower tonnage nomination from the power plant yielding a higher cost per ton.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are debited to accumulated depreciation. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability. For nonregulated operations, non-ARO removal cost is expensed as incurred (see Accounting for Asset Retirement Obligations section of this note).

Accounting for Asset Retirement Obligations

The following is a reconciliation of 2003 and 2004 aggregate carrying amounts of asset retirement obligations by Registrant Subsidiary:

	Balance at January 1, 2003	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at December 31, 2003
			(in millions)			
AEGCo (a)	$ 1.1	$ -	$ -	$ -	$ -	$ 1.1
APCo (a)	20.1	1.6	-	-	-	21.7
CSPCo (a)	8.1	0.6	-	-	-	8.7
I&M (b)	516.1	37.1	-	-	-	553.2
OPCo (a)	39.5	3.2	-	-	-	42.7
SWEPCo (c)	-	0.3	8.1	-	-	8.4
TCC (d)	203.2	15.6	-	-	-	218.8

	Balance at January 1, 2004	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at December 31, 2004
			(in millions)			
AEGCo (a)	$ 1.1	$ 0.1	$ -	$ -	$ -	$ 1.2
APCo (a)	21.7	1.7	-	(0.4)	1.6	24.6
CSPCo (a)	8.7	0.7	-	-	2.2	11.6
I&M (b)	553.2	39.8	-	-	118.8	711.8
OPCo (a)	42.7	3.4	-	-	(0.5)	45.6
SWEPCo (c)	8.4	1.3	17.7	-	-	27.4
TCC (d)	218.8	16.7	-	-	13.4	248.9

(a) Consists of asset retirement obligations related to ash ponds.

(b) Consists of asset retirement obligations related to ash ponds ($1.2 million and $1.1 million at December 31, 2004 and 2003, respectively) and nuclear decommissioning costs for the Cook Plant ($710.6 million and $552.1 million at December 31, 2004 and 2003, respectively).

(c) Consists of asset retirement obligations related to Sabine Mining in 2004 and 2003, which is now being consolidated under FIN 46 (see FIN 46 Consolidation of Variable Interest Entities section of Note 2), and Dolet Hills in 2004.

(d) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale - Texas Generation Plants on TCCs Consolidated Balance Sheets.

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of December 31 2004, and 2003, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $934 million ($791 million for I&M and $143 million for TCC) and $845 million ($720 million for I&M and $125 million for TCC), respectively, included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&Ms Consolidated Balance Sheets and in Assets Held for Sale - Texas Generation Plants on TCCs Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the year ended December 31, 2002 because the pro forma application of SFAS 143 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during that period.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations, interest is capitalized during construction in accordance with SFAS 34, Capitalization of Interest Costs. Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized for 2004, 2003 and 2002 are as follows:

	2004	2003	2002
		(in millions)	
AEGCo	$ -	$ -	$ 0.4
APCo	14.7	8.5	5.8
CSPCo	6.1	6.3	2.3
I&M	4.1	8.2	6.0
KPCo	0.5	1.7	2.2
OPCo	6.3	5.0	6.7
PSO	0.6	0.8	0.7
SWEPCo	1.1	1.7	0.5
TCC	1.9	1.1	5.1
TNC	0.6	0.8	0.4

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt.

Inventory

Except for PSO and TNC, the regulated domestic utility companies value fossil fuel inventories at the lower of a weighted average cost or market. PSO and TNC record fossil fuel inventories at the lower of cost or market, utilizing the LIFO cost method. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and certain subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billings.

AEP Credit, Inc. factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCos accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, allowing the receivables to be removed from the companys balance sheet (see Sale of Receivables section of Note 16).

Concentrations of Credit Risk and Significant Customers

TNC and TCC have significant customers which on a combined basis account for the following percentages of total Operating Revenues for the periods ended and Accounts Receivable - Customers as of December 31:

	2004	**2003**	**2002**
TCC - two customers			
Percentage of Operating Revenues	74 %	56 %	7 %
Percentage of Accounts Receivable - Customers	48	54	N/A
TNC - three customers			
Percentage of Operating Revenues	79	68	9
Percentage of Accounts Receivable - Customers	57	49	N/A

We monitor credit levels and the financial condition of our customers on a continuing basis to minimize credit risk. We believe adequate provision for credit loss has been made in the accompanying Registrant Financial Statements.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulators review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. Whena fuel cost disallowancebecomes probable, the Registrant Subsidiaries adjust their deferrals and record provisions for estimated refunds to recognize these probable outcomes. For TCC & TNC, their deferred fuel balances will be included in their True-up Proceedings (see Note 6). See Note 5 for the amount of deferred fuel costs by Registrant Subsidiary.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with ratepayers through fuel clauses in Texas (SPP area only), Oklahoma, Louisiana, Kentucky, Arkansas and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings unless recovered in sales price for electricity. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze ended on March 1, 2004. Through subsequent orders, the Indiana Utility Regulatory Commission (IURC) has authorized the billing of capped fuel rates on an interim basis until April 1, 2005. In Indiana, there is an issue as to whether the freeze should be extended through 2007 under an existing corporate separation stipulation agreement. Management disagrees with this interpretation of the stipulation and the matter is pending resolution. In West Virginia, the fuel clause is suspended indefinitely. See Note 4 and Note 6 for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, CSPCo, OPCo, SWEPCo, TCC and TNC), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains and losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, Registrant Subsidiaries record them as assets on the balance sheet. Registrant Subsidiaries test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the Registrant Subsidiaries write off that regulatory asset as a charge against earnings. A write-off of regulatory assets also reduces future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase and sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio, Virginia and Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Beginning in July 2004, as a result of the sale of generation assets in AEP's west zone, AEP is short capacity and must purchase physical power to supply retail and wholesale customers. For power purchased under derivative contracts in AEPs west zone, prior to settlement the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period are recognized as Revenues. If the contract results in the physical delivery of power, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded gross as Purchased Energy for Resale. If the contract does not physically deliver, the previously recorded unrealized gains and losses from MTM valuations are reversed and the settled amounts are recorded as Revenues in the financial statements on a net basis (see Note 13).

Energy Marketing and Risk Management Activities

Registrant Subsidiaries engage in wholesale electricity and coal and emission allowances marketing and risk management activities. Effective October 2002, these activities were focused on wholesale markets where Registrant Subsidiaries own assets. Registrant Subsidiaries activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, Registrant Subsidiaries recorded wholesale marketing and risk management activities using the MTM method of accounting.

In October 2002, EITF 02-3 precluded MTM accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant Subsidiaries implemented this standard for all nonderivative wholesale and risk management transactions occurring on or after October 25, 2002. For nonderivative risk management transactions entered prior to October 25, 2002, Registrant Subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change (see Accounting for Risk Management Contracts section of Note 2).

After January 1, 2003, revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered. Registrant Subsidiaries use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in Revenues in the financial statements on a net basis. In jurisdictions subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

All of the Registrant Subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Certain wholesale marketing and risk management transactions are designated as a hedge of a forecasted transaction, a future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the financial statements in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivatives gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the financial statements when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the financial statements immediately (see Note 13).

Construction Projects for Outside Parties

TCC and TNC engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred and billed to the outside party. Such revenue and related expenses are included in Nonoperating Income and Nonoperating Expenses, respectively, in the financial statements. Contractually billable expenses not yet billed, if significant, are included in Current Assets as Unbilled Construction Costs in the financial statements.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, incremental operation and maintenance costs associated with periodic refueling outages at I&Ms Cook Plant are deferred and amortized over the period beginning with the month following the start of each units refueling outage and lasting until the end of the month in which the same units next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure that all deferred costs are fully amortized by the end of the refueling cycle.

Maintenance Costs

Maintenance costs are expensed as incurred. If it becomes probable that Registrant Subsidiaries will recover specifically incurred costs through future rates, a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

Registrant Subsidiaries use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

Registrant Subsidiaries, as agents for some state and local governments, collect from customers certain excise taxes levied by those state or local governments on customers. Registrant Subsidiaries do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Charges.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The amortization expense is included in interest charges.

Registrant Subsidiaries classify instruments that have an unconditional obligation requiring them to redeem the instruments by transferring an asset at a specified date as liabilities on their balance sheets. Those instruments consist of cumulative preferred stock subject to mandatory redemption as of December 31, 2004 and 2003. Beginning July 1, 2003, the Registrant Subsidiaries classify dividends on these mandatorily redeemable preferred shares as Interest Charges. In accordance with SFAS 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, dividends from prior periods remain classified as preferred stock dividends, a component of Preferred Stock Dividend Requirements, on their financial statements.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain Registrant Subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

SWEPCo is the only Registrant Subsidiary with an intangible asset with a finite life and amortizes the asset over its estimated life to its residual value (see Note 3). The Registrant Subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2004 and 2003.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed I&M and TCC to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

acceptable investments (rated investment grade or above);

maximum percentage invested in a specific type of investment;
prohibition of investment in obligations of the applicable company or its affiliates; and
withdrawals only for payment of decommissioning costs and trust expenses.

Trust funds are maintained for each regulatory jurisdiction and managed by external investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds for amounts relating to I&Ms Cook Plant and are included in Assets Held for Sale-Texas Generation Plants for amounts relating to TCCs ownership in STP (see Assets Held for Sale section of Note 10).

These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss). There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheets in the capitalization section. Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of December 31, 2004 and 2003 is shown in the following table.

	December 31,	
	2004	2003
	(in thousands)	
Components		
Cash Flow Hedges:		
APCo	$ (9,324)	$ (1,569)
CSPCo	1,393	202
I&M	(4,076)	222
KPCo	813	420
OPCo	1,241	(103)
PSO	400	156
SWEPCo	(820)	184
TCC	657	(1,828)
TNC	285	(601)
Minimum Pension Liability:		
APCo	$ (72,348)	$ (50,519)
CSPCo	(62,209)	(46,529)
I&M	(41,175)	(25,328)
KPCo	(9,588)	(6,633)
OPCo	(75,505)	(48,704)
PSO	(325)	(43,998)
SWEPCo	(360)	(44,094)
TCC	(4,816)	(60,044)
TNC	(413)	(26,117)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo and OPCo are wholly-owned subsidiaries of AEP and PSO, SWEPCo, TCC and TNC are owned by a wholly-owned subsidiary of AEP; therefore, none are required to report EPS.

Reclassification

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2004 that we have determined relate to our operations.

FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FASB Staff Position (FSP) FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, effective April 1, 2004, retroactive to January 1, 2004. The new disclosure standard provides authoritative guidance on the accounting for any effects of the Medicare prescription drug subsidy under the Act. It replaces the earlier FSP FAS 106-1, under which APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC previously elected to defer accounting for any effects of the Act until the FASB issued authoritative guidance on the accounting for the Medicare subsidy.

Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106s 10 percent corridor. See Note 11 for additional information related to the effects of implementation of FAS 106-2 on our postretirement benefit plans.

SFAS 123 (revised 2004) Share-Based Payment (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, Share-Based Payment. SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) 25. The statement is effective as of the first interim or annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement.

We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

SFAS 153 Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29

In December 2004, the FASB issued SFAS 153, Exchange of Nonmonetary Assets: an amendment of APB Opinion No. 29 to eliminate the Opinion 29 exception to fair value for nonmonetary exchanges of similar productive assets and to replace it with a general exception for exchange transactions that do not have commercial substance. We expect to implement SFAS 153 prospectively, beginning July 1, 2005. We do not expect the effect to be material to our results of operations, cash flows or financial condition.

FIN 46 (revised December 2003)Consolidation of Variable Interest Entities and FIN 46 Consolidation of Variable Interest Entities

We implemented FIN 46, Consolidation of Variable Interest Entities, effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, Consolidated Financial Statements, to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, PSO, SWEPCo and TCC deconsolidated the trusts that held mandatorily redeemable trust preferred securities.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Also, after consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabines revenues against SWEPCos fuel expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate, and there was no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG, an entity formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMGs revenues against OPCos operating lease expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG (see Gavin Scrubber Financing Agreement in Note 15).

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. We implemented FIN 46R effective March 31, 2004 with no material impact to our financial statements.

EITF Issue 03-13 Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations

This issue developed a model for evaluating which cash flows are to be considered in determining whether cash flows have been or will be eliminated and what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We will apply this issue to components that are disposed of or classified as held for sale in periods beginning after December 15, 2004.

FASB Staff Position 109-1 Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Activities Provided by the American Jobs Creation Act of 2004

On October 22, 2004 the American Jobs Creation Act of 2004 (Act) was signed into law. The Act included tax relief for domestic manufacturers (including the production, but not the delivery of electricity) by providing a tax deduction up to 9 percent (when fully phased-in in 2010) on a percentage of qualified production activities income. Beginning in 2005 and for 2006, the deduction is 3 percent of qualified production activities income. The deduction increases to 6 percent for 2007, 2008 and 2009. The FASB staff has indicated that this tax relief should be treated as a special deduction and not as a tax rate reduction. While the U.S. Treasury has issued general guidance on the calculation of the deduction, this guidance lacks clarity as to determination of qualified production activities income as it relates to utility operations. We believe that the special deduction for 2005 and 2006 will not materially affect the results of operations, cash flows, or financial condition.

Future Accounting Changes

The FASBs standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, asset retirement obligations, fair value measurements, business combinations, revenue recognition, pension plans, liabilities and equity, earnings per share calculations, accounting changes and related tax impacts as applicable. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

EXTRAORDINARY ITEMS

In the fourth quarter of 2004, as part of its True-up Proceeding, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset related to its transition to retail competition. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis, including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCCs stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in the CenterPoint Order (see Wholesale Capacity Auction True-up section of Note 6). These net adjustments were recorded as an extraordinary item in accordance with SFAS 101 Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71 and are reflected in TCCs Consolidated Statements of Operations as Extraordinary Loss on Stranded Cost Recovery, Net of Tax.

In 2003 an extraordinary item of $177,000, net of tax of $95,000, was recorded at TNC for the discontinuance of regulatory accounting under SFAS 71 in compliance with a FERC Order dated December 24, 2003 approving a Settlement. The Registrant Subsidiaries had no extraordinary items in 2002.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 Accounting for Contracts Included in Energy Trading and Risk Management Activities, and related interpretive guidance. Registrant Subsidiaries except PSO and AEGCo have recorded after tax charges against net income in Cumulative Effect of Accounting Changes on the Registrant financial statements in the first quarter of 2003. These amounts are recognized as the positions settle.

Asset Retirement Obligations

In the first quarter of 2003, Registrant Subsidiaries except PSO and AEGCo recorded a cumulative effect of accounting change for Asset Retirement Obligations in accordance with SFAS 143.

The following is a summary by Registrant Subsidiary of the cumulative effect of changes in accounting principles recorded in 2003 for the adoptions of SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	SFAS 143 Cumulative Effect		EITF 02-3 Cumulative Effect	
	(in millions)			
	Pretax Income (Loss)	After tax Income (Loss)	Pretax Income (Loss)	After tax Income (Loss)
APCo	$ 128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	49.0	29.3	(3.1)	(2.0)
I&M	-	-	(4.9)	(3.2)
KPCo	-	-	(1.7)	(1.1)
OPCo	213.6	127.3	(4.2)	(2.7)
SWEPCo	13.0	8.4	0.2	0.1
TCC	-	-	0.2	0.1
TNC	4.7	3.1	-	-

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the Registrant Subsidiaries.

Acquired Intangible Assets

SWEPCos acquired intangible asset subject to amortization is $18.8 million at December 31, 2004 and $21.7 million at December 31, 2003, net of accumulated amortization and is included in Deferred Charges on the Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization are:

		December 31, 2004		December 31, 2003	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced royalties	10	$ 29.4	$ 10.6	$ 29.4	$ 7.7

Amortization of the intangible asset was $2.9 million for 2004 and $3 million for 2003 and2002. SWEPCos estimated total amortization is $3 million for each year 2005 through 2010 and $1 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to the Nuclear Plant Restart and the Merger with CSW.

TNC Fuel Reconciliations - Affecting TNC

In 2002, TNC filed with the PUCT to reconcile fuel costs and defer the unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in its True-up Proceeding. As a result of the introduction of customer choice on January 1, 2002, this fuel reconciliation for the period from July 2000 through December 2001 is the final fuel reconciliation for TNCs ERCOT service territory.

Through 2004, TNC provided $30 million for various disallowances recommended by the ALJ and accepted by the PUCT in open session of which $20 million was recorded in 2003 and $10 million in 2004. On October 18, 2004, the PUCT issued a final order which concluded that the over-recovery balance was $4 million. TNC has fully provided for the PUCTs final order in this proceeding. TNC has sought declaratory and injunctive relief in Federal District Court for $8 million of its provision resulting from the PUCTs rejection of TNCs application of a FERC-approved tariff on the basis that the interpretation of the tariff is within the exclusive jurisdiction of the FERC and not the PUCT. TNC has also appealed various other issues to state District Court in Travis County for which it has provided $22 million. Another party has also filed a state court appeal. TNC will pursue vigorously these proceedings but at present cannot predict their outcome.

In February 2002, TNC received a final PUCT order in a previous fuel reconciliation covering the period July 1997 through June 2000 and reflected the order in its financial statements. In September 2004, that decision was affirmed by the Third Court of Appeals. No appeal was filed with the Supreme Court of Texas.

TCC Fuel Reconciliation - Affecting TCC

In 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the True-up Proceeding. This reconciliation covers the period from July 1998 through December 2001.

On February 3, 2004, the ALJ issued a Proposal for Decision (PFD) recommending that the PUCT disallow $140 million of eligible fuel costs. In May 2004, the PUCT accepted most of the ALJs recommendations in the TCC case, however, the PUCT rejected the ALJs recommendation to impute capacity to certain energy-only purchased power contracts and remanded the issue to the ALJ to determine if any energy-only purchased power contracts during the reconciliation period include a capacity component that is not recoverable in fuel revenues. In testimony filed in the remand proceeding, TCC asserted that its energy-only purchased power contracts do not include any capacity component. Intervenors, including the Office of Public Utility Counsel, have filed testimony recommending that $15 million to $30 million of TCCs purchased power costs reflect capacity costs which are not recoverable in the fuel reconciliation. The ALJ issued a report on January 13, 2005 on the imputed capacity remand recommending that specified energy-only purchased power contracts include a capacity component with a value of $2 million. At its February 24, 2005 open meeting, thePUCT reviewed the ALJ report and also ruled that specified energy-only purchased power contracts include a capacity component of $2 million. As a result of the PUCTs acceptance of most of the ALJs recommendations in TCCs case and the PUCTs rejection in the TNC case of our interpretation of its FERC tariff, TCC has recorded provisions totaling $143 million, with $81 million provided in 2003 and $62 million in 2004. The over-recovery balance and the provisions for probable disallowances totaled $212 million including interest at December 31, 2004.

Management believes they have materially provided for probable to-date disallowances in TCCs final fuel reconciliation pending receipt of a final order. A final order has not yet been issued in TCCs final fuel reconciliation. An order from the PUCT, disallowing amounts in excess of the established provision, could have a material adverse effect on future results of operations and cash flows. We will continue to challenge adverse decisions vigorously, including appeals and challenges in Federal Court if necessary. Additional information regarding the True-up Proceeding for TCC can be found in Note 6.

TNC FERC Wholesale Fuel Complaints - Affecting TNC

Certain TNC wholesale customers filed a complaint with the FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003.

SWEPCo Texas Fuel Reconciliation - Affecting SWEPCo

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period from January 2000 through December 2002. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation proceeding. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In April 2004, the PUCT approved the settlement.

SWEPCo Fuel Factor Increase - Affecting SWEPCo

On November 5, 2004, SWEPCo filed a petition with the PUCT to increase its annual fixed fuel factor by $29 million. SWEPCo and the various parties to the proceedings reached a settlement effective January 31, 2005 that increases its annual fixed fuel factor revenues by approximately $25 million or approximately 18% over the amount that would be collected by the fuel factors currently in effect. The settlement agreement was approved by the PUCT on January 31, 2005. Actual fuel costs will be subject to a review and approval in a future fuel reconciliation.

SWEPCo Louisiana Fuel Audit - Affecting SWEPCo

The Louisiana Public Service Commission (LPSC) is performing an audit of SWEPCos historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has overcharged them for fuel costs since 1975. The LPSC consolidated the customer complaints and audit. In testimony filed in this matter, the LPSC Staff recommended refunds of approximately $5 million. Subsequently, surrebuttal testimony filed by the LPSC Staff recognized that SWEPCos costs were reasonable and that most costs could be recovered through the fuel adjustment clause pending LPSC approval. While initial indications from the LPSC Staff surrebuttal testimony would not indicate a material disallowance, management cannot predict the ultimate outcome in this proceeding. If the LPSC or the Court does not agree with LPSC Staff recommendations, it could have an adverse effect on future results of operations and cash flows.

PSO Fuel and Purchased Power - Affecting PSO

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the Corporation Commission of the State of Oklahoma (OCC) to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSOs 2001 fuel and purchased power practices. PSO filed testimony in February 2004.

An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $9 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and, if corrected, could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also argued that off-system sales margins were allocated incorrectly. The intervenors reallocation of such margins would reduce PSOs recoverable fuel costs by $7 million for 2000 and $11 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $9 million. The intervenor and the OCC Staff also recommended recalculation of PSOs fuel costs for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. After reviewing the briefs, the ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. In January 2005, the OCC conducted a hearing on the jurisdictional matter and a ruling is expected in the near future. Management is unable to predict the ultimate effect of these proceedings on PSOs revenues, results of operations, cash flows and financial condition.

Virginia Fuel Factor Filing - Affecting APCo

On October 29, 2004, APCo filed a request with the Virginia State Corporation Commission (Virginia SCC) to increase its fuel factor effective January 1, 2005. The requested factor is estimated to increase revenues by approximately $19 million on an annual basis. This increase reflects a continuing rise in the projected cost of coal in 2005. By order dated November 16, 2004, the Virginia SCC approved APCos request on an interim basis, pending a hearing held in February 2005. The Virginia SCC issued an order on February 11, 2005 approving the January 1, 2005 interim fuel factor, which is subject to final audit. This fuel factor adjustment will increase cash flows without impacting results of operations as any over-recovery or under-recovery of fuel cost would be deferred as a regulatory liability or a regulatory asset.

Indiana Fuel Order - Affecting I&M

On August 27, 2003, the IURC ordered certain parties to negotiate the appropriate action on I&Ms fuel cost recovery beginning March 1, 2004, following the February 2004 expiration of a fixed fuel adjustment charge that capped fuel recoveries (fixed pursuant to a prior settlement of Cook Nuclear Plant outage issues). I&M agreed, contingent on AEP implementing corporate separation for some of its subsidiaries, to a fixed fuel adjustment charge beginning March 2004 and continuing through December 2007. Although we have not corporately separated, certain parties believe the fixed fuel adjustment charge should continue beyond February 2004. Negotiations to resolve this issue are ongoing. The IURC ordered that the fixed fuel adjustment charge remain in place, on an interim basis, through April 2004.

In April 2004, the IURC issued an order that extended the interim fuel factor from May through September 2004, subject to true-up to actual fuel costs following the resolution of the issue regarding the corporate separation agreement. The IURC also reopened the corporate separation docket to investigate issues related to the corporate separation agreement. In July 2004, we filed for approval of a fuel factor for the period October 2004 through March 2005. On September 22, 2004, the IURC issued another order extending the interim fuel factor from October 2004 through March 2005, subject to true-up upon resolution of the corporate separation issues. At December 31, 2004, I&M has under-recovered its fuel costs by $2 million. If I&Ms net recovery should remain an under-recovery and if I&M would be required to continue to bill the existing fixed fuel adjustment factor that caps fuel revenues, I&Ms future results of operations and cash flows would be adversely affected.

Michigan 2004 Fuel Recovery Plan - Affecting I&M

On September 30, 2003, I&M filed its 2004 Power Supply Cost Recovery (PSCR) Plan with the Michigan Public Service Commission (MPSC) requesting fuel and power supply recovery factors for 2004, which were implemented pursuant to statute effective with January 2004 billings. A public hearing was held on March 10, 2004. On June 4, 2004, the ALJ recommended that net SO_2 and NO_x credits be excluded from the fuel recovery mechanism. I&M filed its exceptions in June 2004. If the ALJs recommendation is adopted by the MPSC and in a future period SO_2 and NO_x are a net cost, it would adversely affect results of operations and cash flows. On September 30, 2004, I&M filed its 2005 PSCR Plan, which reflects net credits of approximately $5 million.

TCC Rate Case - Affecting TCC

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCCs proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%.

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCCs requested $67 million annual rate increase. Their recommendations ranged from a decrease in annual existing rates of approximately $100 million to an increase in TCCs current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a nonunanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCCs rate request from an increase of $67 million to an increase of $41 million.

On July 1, 2004, the ALJs who heard the case issued their recommendations which included a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded back to the ALJs for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling, the PUCT remanded six other issues to the ALJs requesting revisions to clarify and support the recommendations in the PFD.

The PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCCs calculations, the ALJs recommendations would reduce TCCs annual existing rates between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings.

On November 16, 2004, the ALJs issued their PFD on remand, increasing their recommended annual rate reduction to a range of $51 million to $78 million, depending on the amount disallowed related to affiliated AEPSC billed expenses. At the January 13, 2005 and January 27, 2005 open meetings, the Commissioners considered a number of issues, but deferred resolution of the affiliated AEPSC billed expenses issue, among other less significant issues, until after additional hearings scheduled for March 2005. Adjusted for the decisions announced by the Commissioners in January 2005, the ALJs disallowance would yield an annual rate reduction of a range of $48 million to $75 million. If TCC were to prevail on the affiliated expenses issue and all remaining issues, the result would be annual rate increase of $6 million. When issued, the PUCT order will affect revenues prospectively. An order reducing TCCs rates could have a material adverse effect on future results of operations and cash flows.

TCC and TNC ERCOT Price-to-Beat (PTB) Fuel Factor Appeal - Affecting TCC and TNC

Several parties including the OPC and cities served by both TCC and TNC appealed the PUCTs December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court also ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCTs original decision will ultimately be upheld. If the District Courts decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in the years 2002 through 2004 resulting in an adverse effect on TCCs and TNCs future results of operations and cash flows.

TCC Unbundled Cost of Service (UCOS) Appeal - Affecting TCC

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCCs UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCCs excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCTs UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Courts decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on TCCs future results of operations and cash flows.

SWEPCo Louisiana Compliance Filing - Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. The LPSCs merger order also provides that SWEPCos base rates are capped at the present level through mid-2005. In April 2004, SWEPCo filed updated financial information with a test year ending December 31, 2003 as required by the LPSC. Both filings indicated that SWEPCos current rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in SWEPCos Louisiana jurisdictional base rates. SWEPCos rebuttal testimony was filed on January 16, 2005. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ordered in the future, it would adversely impact SWEPCos future results of operations and cash flows.

SWEPCo Louisiana Service Quality Improvement Program (SQIP) - Affecting SWEPCo

In the 1999 merger proceeding before the LPSC, the LPSC adopted a Service Quality Improvement Program (SQIP) for SWEPCo. On October 8, 2004, SWEPCo filed to amend the SQIP to increase its tree management and trimming expenditures by $5 million above the minimum expenditures currently required by the SQIP and defer these incremental expenses for future rate recovery. On December 9, 2004, the LPSC approved SWEPCos request to defer the incremental cost of tree management and trimming expenditures beginning December 1, 2004 and ending December 31, 2006 and has authorized SWEPCo to accrue interest based on its weighted average cost of capital. SWEPCo will be permitted to include the deferred costs, including interest, as a cost of service in future base rate proceedings, but only to the extent the deferrals are necessary to allow SWEPCo to recover its authorized return on equity during the time period the expenses were incurred (i.e. an earnings test). The earnings test will not be effective until calendar year 2005. In future rate proceedings, the amortization period will not exceed three years and amortization will commence with the recovery of such costs in base rates.

PSO Rate Review - Affecting PSO

In February 2003, the OCC Staff filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC Staffs request. PSOs initial response indicated that its annual revenues were $36 million less than costs. The June 2004 filing updated PSOs request and indicated a $41 million revenue deficiency. As a result, PSO sought OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSOs existing revenues.

In August 2004, PSO filed a motion to amend the timeline to consider new service quality and reliability requirements, which took effect on July 1, 2004. Also in August 2004, the OCC approved a revised schedule. In October 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. In November 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO sought interim approval to collect annual incremental distribution tree trimming costs of approximately $23 million from its customers. Intervenors and the OCC Staff filed testimony recommending that the interim rate relief requested by PSO be modified or denied. The OCC issued an order on PSOs interim request in January 2005, which allows PSO to recover up to an additional $12 million annually for reliability activities beginning in December 2004. Expenses exceeding that amount and the amount currently included in base rates will be considered in the base rate case.

The OCC Staff and intervenors filed testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in January 2005. Their recommendations ranged from a decrease in annual existing rates between $15 million and $36 million. In addition, one party recommended that the OCC require PSO file additional information regarding its natural gas purchasing practices. In the absence of such a filing, this party suggested that $30 million of PSOs natural gas costs not be recovered from customers because it failed to implement a procurement strategy that, according to this party, would have resulted in lower natural gas costs. OCC Staff and intervenors recommended a return on common equity ranging from 9.3% to 10.11%. PSOs rebuttal testimony was filed in February 2005, and that testimony reflects a number of adjustments to PSOs June 2004 updated filing. These adjustments result in a decrease of PSOs revenue deficiency in this case from $41 million to $28 million, although approximately $9 million of that decrease are items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on PSOs revenues, results of operations, cash flows and financial condition.

APCo Virginia Regional Transmission Entity (RTE) Credit Rider - Affecting APCo

Pursuant to a stipulation agreement approved by the Virginia SCC by order dated August 30, 2004 in APCos Virginia RTO approval proceeding in which APCo requested approval to become a member of PJM, a RTE Credit Rider became effective January 1, 2005. The RTE Credit Rider is designed to reduce APCos annual Virginia jurisdictional revenues by approximately $2 million. Under the terms of the stipulation agreement, the RTE Credit Rider will be adjusted to produce a $3 million annual Virginia jurisdictional revenue reduction effective on January 1 of the year following the year in which Dominion (Virginia Power) becomes an integrated member of PJM. The RTE Credit Rider will expire at the earlier of December 31, 2010 or upon a change in APCos base rates as a result of a base rate case filed by APCo.

KPCo Stipulation and Settlement Agreement - Affecting AEGCo, I&M and KPCo

On October 25, 2004, KPCo filed an application requesting the KPSC to approve the terms and provisions of a Stipulation and Settlement Agreement among KPCo, the Office of the Kentucky Attorney General and the Kentucky Industrial Utility Customers. The Stipulation: (1) extends a unit power agreement for approximately 18 years, until December 7, 2022, which obligates KPCo to pay 15 percent of the costs associated with two 1,300 MW generating units in Rockport, Indiana for 15 percent of the units generating output; (2) modifies KPCos off-system sales clause tariff to reflect as an expense the environmental costs attributable to off-system sales; and (3) establishes a schedule for KPCo to file its next integrated resource plan, and provides for retail rate recovery of supplemental payments associated with the extension of the unit power agreement and the settlement of other regulatory matters. On December 13, 2004, the KPSC issued its order approving the terms and provisions of the Stipulation and Settlement Agreement. The FERC approved the extension of the unit power agreement on December 29, 2004. KPCo will recover an additional $5 million annually during the first five years and $6 million annually for the remaining 13 years of the 18- year extension.

PSO Lawton Power Supply Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration Incorporated seeking avoided cost payments and approval of a power supply agreement, the OCC issued an order approving payment of avoided costs and a Power Supply Agreement (Agreement). Among other things, in the order, the OCC did not approve recovery of the costs of the Agreement.

In December 2003, PSO filed an appeal of the OCCs order with the Oklahoma Supreme Court. In the appeal, PSO maintains that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. Should the OCCs order be upheld by the Supreme Court, PSO anticipates full recovery of the costs of the Agreement. However, if the OCC was to deny recovery of a material amount, it would adversely affect future results of operations and cash flows.

Upon resolution of this issue, management would review any transaction for the effect, if any, on the balance sheet relating to lease and FIN 46R accounting.

KPCo Environmental Surcharge Filing - Affecting KPCo

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCos cost of compliance with the CAA.

RTO Formation/Integration - Affecting APCo, CSPCo, I&M, KPCo and OPCo

Based on FERC approvals in response to nonaffiliated companies requests to defer RTO formation costs, the AEP East companies deferred costs incurred under FERC orders to form a new RTO (the Alliance RTO) or subsequently to join an existing RTO (PJM). In July 2003, the FERC issued an order approving the AEP East companies continued deferral of both Alliance RTO formation costs and PJM integration costs, including the deferral of a carrying charge thereon. The AEP East companies have deferred approximately $37 million of RTO formation and integration costs and related carrying charges through December 31, 2004. Amounts per company are as follows:

Company	(in millions)

APCo	$	10.5
CSPCo		4.4
I&M		8.0
KPCo		2.4
OPCo		11.9

In its July 2003 order, the FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the OATT to be charged by PJM. Management believes that the FERC will grant permission for prudently incurred deferred RTO formation/integration costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions treatment of the AEP East companies portion of the OATT as these companies file rate cases. As of December 31, 2004, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo and OPCo until January 1, 2006.

In August 2004, the AEP East companies filed an application with the FERC dividing the RTO formation/integration costs between PJM-incurred integration costs billed to them including related carrying charges, and all other RTO formation/integration costs. AEP East companies intend to file with the FERC to request that deferred PJM-incurred integration costs billed to them be recovered from all PJM customers. Management anticipates the other RTO formation/integration costs will be recovered through transmission rates in the AEP East zone. The AEP East companies will be responsible for paying most of the amount allocated by the FERC to the AEP East zone since it will be attributable to their internal load. In the August 2004 application, the AEP East companies requested permission to amortize over 15 years beginning January 1, 2005 the cost to be billed within the AEP East zone which represents approximately one-half of the total deferred RTO formation/integration costs. The AEP East companies also requested to begin amortizing the deferred PJM-billed integration costs on January 1, 2005, AEP East companies but did not propose an amortization period in the application. The FERC has not ruled on the application.

The AEP East companies integrated into PJM on October 1, 2004. The AEP East companies intend to file a joint request with other new PJM members to recover approximately one-half of the deferred RTO formation/integration costs (i.e. the PJM-incurred integration expenses billed to the AEP East companies) through a new charge in the PJM OATT that would apply to all loads and generation in the PJM region during a 10-year period beginning in May 2005. The AEP East companies will expense their portion of the PJM-incurred integration costs billed by PJM under the new charge. The AEP East companies will amortize the remaining portion of our RTO formation/integration costs over the period to be approved by the FERC and seek recovery of such costs in the retail rates for each of the AEP East companies state jurisdictions. Management believes that it is probable that the FERC will approve recovery of the PJM-incurred integration costs to be billed to the AEP East companies through the PJM OATT and that the FERC will grant a long enough amortization period to allow for the opportunity for recovery of the non-PJM incurred RTO formation/integration costs in the AEP East retail jurisdictions. If the FERC ultimately decides not to approve an amortization period that would provide the AEP East companies with the opportunity to include such costs in future retail rate filings or the FERC or the state commissions deny recovery of these deferred costs the AEP East companies future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates - Affecting APCo, CSPCo, I&M, KPCo and OPCo

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO Participants, including AEP East companies, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO Participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC is expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that the AEP East companies previously recovered from T&O service customers to mainly AEPs native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP East companies for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP East companies accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP East companies and Exelon filed joint comments and protests with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an orderindicating that the SECA transition rates would be subject to refund or surcharge andset for hearing all remaining aspects of the compliance filings to the November 18 order, including AEP's request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues within the PJM/MISO Expanded Footprint for the twelve months ended September 30, 2004, the last twelve months prior to the AEP East companies joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEPs internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP East companies for their lost T&O revenues through March 31, 2006, or if any increase in the AEP East companies transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding - Affecting AEP East companies

In its July 2002 order conditionally accepting the AEP East companies choice to join PJM, the FERC directed AEP East companies, ComEd, MISO and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO. In December 2003, AEP East companies and ComEd jointly filed a hold-harmless proposal, which was rejected by the FERC in March 2004 without prejudice to the filing of a new proposal.

In July 2004, AEP East companies and PJM filed jointly with the FERC a new hold-harmless proposal that was nearly identical to a proposal filed jointly by ComEd and PJM in April 2004. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for April 2005.

The proposed hold-harmless agreement as filed by PJM and AEP East companies specifies that the term of the agreement commences on October 1, 2004 and terminates when the FERC determines that effective internalization of congestion and loop flows is accomplished. The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 to $70 million over the term of the agreement for ComEd and AEP East companies. The recent supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP East companies and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP East companies and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 which is pending approval before the FERC.

At this time, management is unable to predict the outcome of this proceeding. AEP East companies will support vigorously its positions before the FERC. No provision has been established. If the FERC ultimately approves a significant hold-harmless payment to the Michigan and Wisconsin utilities, it would adversely impact results of operations and cash flows.

FERC Market Power Mitigation - Affecting AEP East and AEP West companies

In April 2004, the FERC issued two orders concerning utilities ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. These two screening tests include a pivotal supplier test which determines if the market load can be fully served by alternative suppliers and a market share test which compares the amount of surplus generation at the time of the applicants minimum load. In July 2004, the FERC issued an order on rehearing, affirming its conclusions in the April order and directing the AEP System and two nonaffiliated utilities to file generation market power analyses within 30 days. In the second order, the FERC initiated a rulemaking to consider whether the FERCs current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way.

On August 9, 2004, as amended on September 16, 2004 and November 19, 2004, the AEP System submitted its generation market power screens in compliance with the FERCs orders. The analysis focused on the three major areas in which AEP subsidiaries serve load and own generation resources -- ECAR, SPP and ERCOT, and the first tier control areas for each of those areas.

The pivotal supplier and market share screen analyses that were filed demonstrated that the AEP System does not possess market power in any of the control areas to which it is directly connected (first-tier markets). The AEP System passed both screening tests in all of its first tier markets. In its three home control areas, the AEP System passed the pivotal supplier test. The AEP East companies, as part of PJM, also passed the market share screen for the PJM destination market. TCC and TNC also passed the market share screen for ERCOT. PSO, SWEPCo and TNC did not pass the market share screen as designed by the FERC for the SPP control area.

In a December 17, 2004 order, FERC affirmed the conclusions that the AEP System passed both market power screen tests in all areas except SPP. Because the AEP System did not pass the market share screen in SPP, FERC initiated proceedings under Section 206 of the Federal Power Act in which the AEP West companies are rebuttably presumed to possess market power in SPP. Consequently, their revenues from sales in SPP at market based rates after March 6, 2005 will be collected subject to refund to the extent that prices are ultimately found not to be just and reasonable. On February 15, 2005, although management continues to believe the AEP System does not possess market power in SPP, the AEP West companies filed a response and proposed tariff changes to address FERCs market-power concerns. The proposed tariff change would apply to sales that sink within the service territories of PSO, SWEPCo and TNC within SPP that encompass the AEP-SPP control area, and make such sales subject to cost-based rate caps. PSO, SWEPCo and TNC have requested the amended tariffs to become effective March 6, 2005.

In addition to FERC market monitoring, the AEP East and West companies are subject to market monitoring oversight by the RTOs in which they are a member, including PJM and SPP. These market monitors have authority for oversight and market power mitigation.

Management believes that the AEP System is unable to exercise market power in any region. At this time the impact on future wholesale power revenues, results of operations and cash flows of the FERCs and PJMs market power analysis cannot be determined.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items at Decmber 31:

	AEGCo			APCo		
	2004	2003	Recovery/Refund Period	2004	2003	Recovery/Refund Period

				(in thousands)		
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$ 343,415	$ 325,889	Various Periods (a)
Transition Regulatory Assets - Virginia				25,467	30,855	Up to 6 Years (a)
Unamortized Loss on Reacquired Debt	$ 4,496	$ 4,733	21 Years (b)	18,157	19,005	Up to 28 Years (b)
Asset Retirements Obligations	1,117	928	Various Periods (a)	9,879	9,048	Various Periods (a)
Unrealized Loss on Forward Commitments				13,871	17,006	Various Periods (a)
Other				12,618	15,393	Various Periods (a)
Total Regulatory Assets	$ 5,613	$ 5,661		$ 423,407	$ 417,196	
Regulatory Liabilities:						
Asset Removal Costs	$ 25,428	$ 27,822	(d)	$ 95,763	$ 92,497	(d)
Deferred Investment Tax Credits	46,250	49,589	Up to 18 Years (a)	30,382	30,545	Up to 16 Years (c)
SFAS 109 Regulatory Liability, Net	12,852	15,505	Various Periods (a)			
Over-recovery of Fuel Costs - West Virginia				52,071	55,250	(a)
Unrealized Gain on Forward Commitments				23,270	17,283	Various Periods (a)
Over-recovery of Fuel Costs - Virginia				5,772	13,454	1 Year (b)
Other				-	43	
Total Regulatory Liabilities	$ 84,530	$ 92,916		$ 207,258	$ 209,072	

(a) Amount does not earn a return.

(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	CSPCo			**I&M**		
	2004	**2003**	**Recovery/Refund Period**	**2004**	**2003**	**Recovery/Refund Period**
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 16,481	$ 16,027	Various Periods (a)	$ 147,167	$ 151,973	Various Periods (a)
Transition Regulatory Assets	156,676	188,532	Up to 4 Years (a)			
Unamortized Loss on Reacquired Debt	13,155	13,659	Up to 20 Years (b)	21,039	18,424	Up to 28 Years (b)

Incremental Nuclear Refueling Outage Expenses, Net				44,244	57,326	(c)
DOE Decontamination Assessment				14,215	18,863	Up to 3 Years (a)
Other	25,691	24,966	Various Periods (a)	31,015	29,691	Various Periods (a)
Total Regulatory Assets	$ 212,003	$ 243,184		$ 257,680	$ 276,277	
Regulatory Liabilities:						
Asset Removal Costs	$ 103,104	$ 99,119	(d)	$ 280,054	$ 263,015	(d)
Deferred Investment Tax Credits	27,933	30,797	Up to 16 Years (a)	82,802	90,278	Up to 18 Years (a)
Excess ARO for Nuclear Decommissioning				245,175	215,715	(e)
Unrealized Gain on Forward Commitments				35,534	25,010	Various Periods (a)
Other				33,695	36,258	Various Periods (a)
Total Regulatory Liabilities	$ 131,037	$ 129,916		$ 677,260	$ 630,276	

(a) Amount does not earn a return.

(b) Amount effectively earns a return.
(c) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(d) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.
(e) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. This amount earns a return, which accrues monthly, and will be paid when the nuclear plant is decommissioned.

	KPCo			**OPCo**		
	2004	**2003**	**Recovery/Refund Period**	**2004**	**2003**	**Recovery/Refund Period**
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 103,849	$ 99,828	Various Periods (a)	$ 169,866	$ 169,605	Various Periods (a)
Transition Regulatory Assets				225,273	310,035	3 years (a)
Unamortized Loss on Reacquired Debt	1,021	1,088	Up to 28 Years (b)	11,046	10,172	Up to 34 Years (b)
Other	13,537	12,883	Various Periods (a)	22,189	22,506	Various Periods (a)
Total Regulatory Assets	$ 118,407	$ 113,799		$ 428,374	$ 512,318	
Regulatory Liabilities:						
Asset Removal Costs	$ 28,232	$ 26,140	(c)	$ 102,875	$ 101,160	(c)

Deferred Investment Tax Credits	6,722	7,955	Up to 16 Years (a)	12,539	15,641	Up to 16 Years (a)
Unrealized Gain on Forward Commitments	13,041	9,174	Various Periods (a)			
Other	2,581	1,417	Various Periods (a)	-	3	
Total Regulatory Liabilities	$ 50,576	$ 44,686		$ 115,414	$ 116,804	

(a) Amount does not earn a return.

(b) Amount effectively earns a return.
(c) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	PSO			SWEPCo		
	2004	2003	Recovery/Refund Period	2004	2003	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$ 18,000	$ 3,235	Various Periods (b)
Under-recovered Fuel Costs	$ 366	$ 24,170	1 Year (a)	4,687	11,394	1 Year (a)
Unamortized Loss on Reacquired Debt	14,705	14,357	Up to 11 Years (b)	20,765	19,331	Up to 39 Years (b)
Other	17,246	14,342	Various Periods (d)	16,350	15,859	Various Periods (c)
Total Regulatory Assets	$ 32,317	$ 52,869		$ 59,802	$ 49,819	
Regulatory Liabilities:						
Asset Removal Costs	$ 220,298	$ 214,033	(e)	$ 249,892	$ 236,409	(e)
Deferred Investment Tax Credits	28,620	30,411	Up to 25 Years (d)	35,539	39,864	Up to 13 Years (d)
SFAS 109 Regulatory Liability, Net	21,963	24,937	Various Periods (b)			
Over-recovered Fuel Costs				9,891	4,178	1 Year (a)
Excess Earnings				3,167	2,600	(d)
Unrealized Gain on Forward Commitments	19,676	15,406	Various Periods (d)	15,176	11,793	Various Periods (d)
Other				6,144	6,986	Various Periods (c)
Total Regulatory Liabilities	$ 290,557	$ 284,787		$ 319,809	$ 301,830	

(a) Over/Under-recovered fuel for PSOs Oklahoma jurisdiction & SWEPCos Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts for SWEPCo do earn a return.

(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount does not earn a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	TCC			TNC		
	2004	2003	Recovery/Refund Period	2004	2003	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 15,236	$ 3,249	Various Periods (a)			
Designated for Securitization	1,361,299	1,289,436	(b)			
Under Recovery of Fuel Costs				$ -	$ 6,180	(c)
Wholesale Capacity Auction True-up	559,973	480,000	(c)			
Unamortized Loss on Reacquired Debt	11,842	9,086	Up to 32 Years (a)	2,147	3,929	Up to 15 Years (a)
Deferred Debt - Restructuring	11,596	12,015	Up to 14 Years (a)	6,093	6,579	Up to 14 Years (a)
Other	102,032	127,488	Various Periods (e)	3,783	3,332	Various Periods (e)
Total Regulatory Assets	$ 2,061,978	$ 1,921,274		$ 12,023	$ 20,020	
Regulatory Liabilities:						
Asset Removal Costs	$ 102,624	$ 95,415	(f)	$ 81,143	$ 76,740	(f)
Deferred Investment Tax Credits	107,743	112,479	Up to 24 Years (d)	18,698	19,990	Up to 18 Years (d)
Over-recovery of Fuel Costs	211,526	150,026	(c)	3,920	-	(c)
Retail Clawback	61,384	45,527	(c)	13,924	11,804	(c)
Over-recovery of Transition Charges	14,522	22,499	Up to 12 Years (a)			
Excess Earnings				13,270	14,262	Up to 30 Years (a)
SFAS 109 Regulatory Liability, Net				8,500	13,655	Various Periods (a)
Other	62,131	64,207	Various Periods (e)	1,319	1,826	Various Periods (e)
Total Regulatory Liabilities	$ 559,930	$ 490,153		$ 140,774	$ 138,277	

(a) Amount earns a return.

(b) Amount includes a carrying cost, will be included in TCCs True-up Proceeding and is designated for possible securitization. The cost of the securitization bonds would be recovered over a time period to be determined in a future PUCT proceeding.
(c) See Note 6 Texas Restructuring and Carrying Costs on Net True-up Regulatory Assets for discussion of carrying costs. Amounts will be included in TCCs and TNCs True-up Proceedings for future recovery/refund over a time period to be determined in a future PUCT proceeding.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Designated for Securitization, Wholesale Capacity Auction True-up regulatory assets, Over-recovery of Fuel Costs and Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations established in Texas for industry restructuring provide for the recovery from ratepayers of these net amounts. These amounts require approval of the PUCT in a future True-up Proceeding. See Note 6 for a complete discussion of our plans to seek recovery of these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage restart costs were approved in 1999 by the Indiana Utility Regulatory Commission and Michigan Public Service Commission.

The amount of deferrals amortized to maintenance and other operation expenses under the settlement agreements were $40 million in both 2003 and 2002. The Nuclear Plant Restart regulatory asset was fully amortized as of December 31, 2004 and 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 were amortized as a reduction of revenues. The amortization of amounts deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. In connection with the merger, nonrecoverable merger costs were expensed in 2003 and 2002. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were nonrecoverable change in control payments. Merger transaction and transition costs recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense. Deferred merger costs are included in Other Regulatory Assets in the above tables.

As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas - SWEPCo, TCC, TNC	Rate reductions of $221 million over 6 years.
Indiana - I&M	Rate reductions of $67 million over 8 years.
Michigan - I&M	Customer billing credits of approximately $14 million over 8 years.
Kentucky - KPCo	Rate reductions of approximately $28 million over 8 years.
Oklahoma - PSO	Rate reductions of approximately $28 million over 5 years.
Arkansas - SWEPCo	Rate reductions of $6 million over 5 years.
Louisiana - SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years and a base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Merger Litigation section of Note 7 for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of our eleven electric utility companies (CSPCo, I&M, APCo, OPCo, TCC and TNC) are in various stages of transitioning to customer choice and/or market pricing for the supply of electricity in four of the eleven state retail jurisdictions (Ohio, Texas, Michigan and Virginia) in which the Registrant Subsidiaries operate. The following paragraphs discuss significant events related to industry restructuring in those states.

OHIO RESTRUCTURING - Affecting CSPCo and OPCo

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The Public Utilities Commission of Ohio (PUCO) may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utilitys certified territory or that there is a twenty percent switching rate of the incumbent utilitys load by customer class. Following the MDP, retail customers will receive cost-based regulated distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates.

On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rules provide for a Market Based Standard Service Offer (MBSSO) which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rules also require a fixed-rate Competitive Bidding Process (CBP) for residential and small nonresidential customers and permits a fixed-rate CBP for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the MBSSO and the CBP. Customers who make no choice will be served pursuant to the CBP. The rules also required that electric distribution utilities file an application for MBSSO and CBP by July 1, 2004. CSPCo and OPCo were granted a waiver from making the required MBSSO/CBP filing, pending the outcome of a rate stabilization plan they filed with the PUCO in February 2004. As of December 31, 2004, none of OPCos customers have elected to choose an alternate power supplier and only a modest number of CSPCos small commercial customers has switched suppliers. This is believed to be due to CSPCos and OPCos rates being below market.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEPs generation resources that serve Ohio customers. On January 26, 2005, the PUCO approved the plans with some modifications.

The approved plans include annual fixed increases in the generation component of all customers bills (3% a year for CSPCo and 7% a year for OPCo) in 2006, 2007 and 2008. The plan also includes the opportunity to annually request an additional increase in supply prices averaging up to 4% per year for each company to recover certain new governmentally-mandated increased expenditures set out in the approved plan. The plans maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level in effect on December 31, 2005. Such rates could be adjusted with PUCO approval for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion and ancillary services. The approved plans provide for the continued amortization and recovery of stranded transition generation-related regulatory assets. The plans, as modified by the PUCO, require CSPCo and OPCo to allot a combined total of $14 million of previously provided unspent shopping incentives for the benefit of their low-income customers and economic development over the three-year period ending December 31, 2008 which will not have an effect on net income. The plan also authorized each company to establish unavoidable riders applicable to all distribution customers in order to be compensated in 2006 through 2008 for certain new costs incurred in 2004 and 2005 of fulfilling the companies Provider of Last Resort (POLR) obligations. These costs include RTO administrative fees and congestion costs net of financial transmission revenues and carrying cost of environmental capital expenditures. As a result, in 2005, CSPCo and OPCo expect to record regulatory assets of$8 million and $21 million, respectively, for the subject costsrelated to2004 and $14 million and $52 million, respectively, for expected subject costs related to2005. These regulatory assets totaling $22 million for CSPCo and $73 million for OPCo will be amortized as the costs are recovered through POLR riders in 2006 through 2008. The riders, together with the fixed annual increases in generation rates are estimated to provide additional cumulative revenues to CSPCo and OPCo of $190 million and $500 million, respectively, in the three-year period ended December 31, 2008. Other revenue increases may occur related to other provisions of the plans discussed above.

On February 25, 2005, various intervenors filed Applications for Rehearing with the PUCO regarding their approval of the rate stabilization plans.Management expects the PUCO to address the applications before the end of March 2005. Management cannot predict the ultimate impact these proceedings will have on the results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, CSPCo and OPCo are deferring customer choice implementation costs and related carrying costs in excess of $20 million per company. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through December 31, 2004, CSPCo has incurred $38 million and deferred $18 million and OPCo has incurred $40 million and deferred $20 million of such costs for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the rate stabilization plans, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. Management believes that the deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING - ***Affecting SWEPCo, TCC and TNC***

Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition for all Texas customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNCs business is in SPP.

The Texas Restructuring Legislation, among other things:

- provides for the recovery of net stranded generation costs and other generation true-up amounts through securitization and nonbypassable wires charges,
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
- provides for an earnings test for each of the years 1999 through 2001 and,
- provides for a stranded cost True-up Proceeding after January 10, 2004.

The Texas Restructuring Legislation also required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold two of its affiliated price-to-beat REPs serving ERCOT customers to a nonaffiliated company.

TEXAS TRUE-UP PROCEEDINGS

The True-up Proceedings will determine the amount and recovery of:

net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),

a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCTs excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
final approved deferred fuel balance, and
net carrying costs on true-up amounts.

The PUCT adopted a rule in 2003 regarding the timing of the True-up Proceedings scheduling TCCs filing 60 days after the completion of the sale of TCCs generation assets. Due to regulatory and contractual delays in the sale of its generating assets, TCC has not filed its true-up request. TNC filed its true-up request in June 2004 and updated the filing in October 2004. Since TNC is not a stranded cost company under Texas Restructuring Legislation, the majority of the true-up items in the table below do not apply to TNC.

Net True-up Regulatory Asset (Liability) Recorded at December 31, 2004:

	TCC	TNC
	(in millions)	
Stranded Generation Plant Costs	$ 897	$ -
Net Generation-related Regulatory Asset	249	-
Unrefunded Excess Earnings	(10)	-
Net Stranded Generation Costs	1,136	-
Carrying Costs on Stranded Generation Plant Costs	225	-
Net Stranded Generation Costs Designated for Securitization	1,361	-
Wholesale Capacity Auction True-up	483	-
Carrying Costs on Wholesale Capacity Auction True-up	77	-
Retail Clawback	(61)	(14)
Deferred Over-recovered Fuel Balance	(212)	(4)
Net Other Recoverable True-up Amounts	287	(18)
Total Recorded Net True-up Regulatory Asset (Liability)	$ 1,648	$ (18)

Amounts listed above include fourth quarter 2004 adjustments made to reflect the applicable portion of the PUCTs decisions in prior nonaffiliated utilities True-up Proceedings discussed below.

Net Stranded Generation Costs

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC is the only AEP subsidiary that has stranded generation plant costs under the Texas Restructuring Legislation. TCC elected to use the sale of assets method to determine the market value of its generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCCs generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCCs generation capacity in Texas. TCC received bids for all of its generation plants. In January 2004, TCC agreed to sell its 7.81% ownership interest in the Oklaunion Power Station to a nonaffiliated third party for approximately $43 million. In March 2004, TCC agreed to sell its 25.2% ownership interest in STP for approximately $333 million and its other coal, gas and hydro plants for approximately $430 million to nonaffiliated entities. Each sale is subject to specified price adjustments. TCC sent right of first refusal notices to the co-owners of Oklaunion and STP. TCC filed for FERC approval of the sales of Oklaunion, STP and the coal, gas and hydro plants. TCC received a notice from co-owners of Oklaunion and STP exercising their rights of first refusal; therefore, SEC approval will be required. The original nonaffiliated third party purchaser of Oklaunion has petitioned for a court order declaring its contract valid and the co-owners rights of first refusal void. The sale of STP will also require approval from the NRC. On July 1, 2004, TCC completed the sale of its other coal, gas and hydro plants for approximately $428 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. In order to sell these assets, TCC defeased all of its remaining outstanding first mortgage bonds in May 2004. In December 2003, based on an expected loss from the sale of its generating assets, TCC recognized as a regulatory asset an estimated impairment from the sale of TCCs generation assets of approximately $938 million. The impairment was computed based on an estimate of TCCs generation assets sales price compared to book basis at December 31, 2003. On February 15, 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets. TCC asked the PUCT to rule on the request in April 2005.

On December 17, 2004, the PUCT issued an Order on Rehearing in the CenterPoint True-Up Proceeding (CenterPoint Order). All motions for rehearing of that order were denied on January 18, 2005, and the PUCTs decision is now final and appealable. Among other things, the CenterPoint Order provided certain adjustments to stranded generation plant costs to avoid what the PUCT deemed to be duplicative recovery of stranded costs and the capacity auction true-up amount, as further discussed below (See Wholesale Capacity Auction True-up below). The CenterPoint Order also confirmed that stranded costs are to be determined as of December 31, 2001, and, as also discussed below, the CenterPoint Order identified how carrying costs from that date are to be computed (see Carrying Costs on Net True-Up Regulatory Asset below).

In the fourth quarter of 2004, TCC made adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis (instead of December 31, 2003 book basis), including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCCs stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in the CenterPoint Order discussed below under Wholesale Capacity Auction True-up. These adjustments are reflected as Extraordinary Loss on Stranded Cost Recovery, Net of Tax in TCCs Consolidated Statements of Income. Management believes that with these adjustments to TCCs stranded generation plant costs regulatory asset, they have complied with the portions of the PUCTs to-date orders in other Texas companies True-up Proceedings that apply to TCC.

In addition to the two items discussed above (the $938 million impairment in 2003 and the $185 million adjustment in 2004), TCC had recorded $121 million of impairments in 2002 and 2003 on its gas-fired plants. Additionally, other miscellaneous items and the costs to complete the sales, which are still ongoing, of $23 million are included in the recoverable stranded generation plant costs of $897 million.

The Texas Restructuring Legislation permits TCC to recover as its net stranded generation costs $897 million of net stranded generation plant cost plus its remaining not yet securitized net generation-related transition regulatory asset of $249 million less a regulatory liability for the unrefunded excess earnings of $10 million, discussed below. With the above net extraordinary basis adjustments from applicable portions of the PUCTs prior nonaffiliated true-up orders, TCCs net stranded generation costs before carrying costs totaled $1.1 billion at December 31, 2004.

In the CenterPoint Order, the PUCT decided that net stranded generation costs should be reduced by the present value of deferred investment tax credits (ITC) and excess deferred federal income taxes applicable to generating assets. CenterPoint testified in its True-up Proceeding that acceleration of the sharing of deferred ITC with customers may be a violation of the Internal Revenue Codes normalization provisions. Management agrees with CenterPoint that the PUCTs acceleration of deferred ITC and excess deferred federal income taxes may be a violation of the normalization provisions. As a result, management does not intend to include as a reduction of its net stranded generation costs the present value of TCCs generation-related deferred ITC of $70 million and the present value of excess deferred federal income taxes of $6 million in its future true-up filing. As a result, such amounts are not reflected as a reduction of TCCs net stranded generation costs in the above table. The Internal Revenue Service (IRS) has issued proposed regulations that would make an exception to the normalization provisions for a utility whose electric generation assets cease to be public utility property. If the IRS does not issue final regulations with protective provisions prior to the filing of TCCs true-up, management intends to seek a private letter ruling from the IRS to determine whether the PUCTs action would result in a normalization violation. A normalization violation could result in the repayment of TCCs accumulated deferred ITC on all property, not just generation property, which approximates $108 million as of December 31, 2004, and a loss of the ability to elect accelerated tax depreciation in the future. Management is unable to predict how the IRS will rule on a private letter ruling request and whether TCC will ultimately suffer any adverse effects on its future results of operations and cash flows.

Unrefunded Excess Earnings

The Texas Restructuring Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined by the PUCT for this three-year period were $3 million for SWEPCo, $42 million for TCC and $15 million for TNC. TCC, TNC and SWEPCo challenged the PUCTs treatment of fuel-related deferred income taxes in the computation of excess earnings and appealed the PUCTs final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. However, upon further appeal of the District Court ruling upholding the PUCT decision, the Third Court of Appeals reversed the PUCT order and the District Courts judgment. The District Court remanded to the PUCT an appeal of the same issue from the PUCTs 2001 order upon agreement of the parties after issuance of the Third Court of Appeals decision. On September 14, 2004, the parties to the PUCT remand reached an agreement, which changed the method for calculating excess earnings which, in turn, revised the calculation for 2000 and 2001 consistent with the ruling of the court. The PUCT issued a final order approving the agreement in October 2004. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, all three companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Courts decision and credited amortization expense during the third quarter of 2003. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant cost, excess earnings have been applied to reduce T&D capital expenditures and are not a true-up item.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order had no additional effect on reported net income but reduces cash flows over the refund period. The remaining $10 million to be refunded is recorded as a regulatory liability at December 31, 2004 and will be included as a reduction to TCCs net stranded generation costs unless it has been fully refunded. Management believes that TCC has stranded generation plant costs and that it is, therefore, inconsistent with the Texas Restructuring Legislation for the PUCT to have ordered a refund prior to TCCs True-up Proceeding. TCC appealed the PUCTs premature refund of excess earnings to the Travis County District Court. That court affirmed the PUCTs decision and further ordered that the refunds be provided to ultimate customers. TCC has appealed the decision to the Third Court of Appeals.

In January 2005, intervenors filed testimony in TNCs True-up Proceeding recommending that TNCs excess earnings be increased by approximately $5 million to reflect carrying charges on its excess earnings for the period from January 1, 2002 to March 2005. A decision from the PUCT will likely be received in the second quarter of 2005.

Wholesale Capacity Auction True-up

The Texas Restructuring Legislation required that electric utilities and their affiliated power generation companies (PGCs) offer for sale at auction, in 2002, 2003 and thereafter, at least 15% of the PGCs Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. According to the legislation, the actual market power prices received in the state-mandated auctions are used to calculate wholesale capacity auction true-up revenues for recovery in the True-up Proceeding. According to PUCT rules, the wholesale capacity auction true-up is only applicable to the years 2002 and 2003. Based on its auction prices, TCC recorded a regulatory asset and related revenues of $262 million in 2002 and $218 million in 2003 which represented the quantifiable amount of the wholesale capacity auction true-up. The cumulative amount before carrying costs was adjusted to $483 million in the fourth quarter of 2004. TCC also recorded $77 million of carrying costs in the fourth quarter of 2004 related to the wholesale capacity auction true-up, increasing the total asset to $560 million.

In the CenterPoint Order, the PUCT made three significant adverse adjustments to CenterPoints and its affiliated PGCs request for recovery related to its capacity auction true-up regulatory asset. First, the PUCT determined that CenterPoint had not met what the PUCT interpreted as a requirement to sell 15% of its generation capacity at the state-mandated auctions. Accordingly, an adjustment was made to reflect prices obtained in other auctions of CenterPoints affiliated PGCs generation. Parties to the TCC proceeding may also contend that TCC has not met the requirement to auction 15% of its generation capacity. However, based on facts not applicable to the CenterPoint case, TCC will contend that it has met the requirement. Even if it were determined that TCC has not complied with the requirement, facts unique to TCC might mitigate the potential impact and make the method of calculating an impact uncertain. Since the facts in the CenterPoint decision differ from TCCs facts and circumstances, TCC has not recorded any provisions to reflect a similar adverse adjustment to its net true-up regulatory asset.

Second, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002-2003. The PUCT then determined that depreciation is a component of that recovery and, because depreciation represents a return of investment in generation assets, it disallowed 2002 and 2003 depreciation as a duplicative recovery of stranded costs. In the CenterPoint Order the PUCT determined that there was a duplication of depreciation due to the fact that the stranded generation plant costs also include amounts depreciated in 2002 and 2003 because the stranded generation plant costs were determined as of December 31, 2001. TCC disagrees that the purpose of the capacity auction true-up is to provide a traditional regulated recovery during 2002 through 2003. Moreover, TCC will contend, among other things, that the PUCTs method of calculating the capacity auction true-up did not permit TCC to fully recover 2002 through 2003 depreciation expense. Nonetheless, based on the determination made by the PUCT in the CenterPoint case and the probability that it will interpret the law in the same manner in TCCs case, TCC recorded a $238 million reduction to its stranded generation plant costs in December 2004 which is reflected as a component of the Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in TCCs Consolidated Statements of Income.

Third, the PUCT determined in the CenterPoint case that any nonfuel revenues produced by the capacity auction true-up regulatory asset which exceed nonfuel revenues for 2002-2003 from traditional regulation is a margin or return which is duplicative of the carrying cost. As noted above, TCC intends to challenge the conclusion that the capacity auction true-up was intended to provide a traditional regulated recovery. In addition, TCC will contend, that when applied to TCC, the calculation adopted for CenterPoint in which the PUCT determined that CenterPoint had duplicative return of carrying costs actually produces a $206 million negative margin. It will be TCCs position that it should have the right to recover the negative margin if the purpose of the capacity auction is to allow a traditional regulated recovery. As a result, TCC has recorded no adjustment to reflect this determination in the CenterPoint case.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is referred to as the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. In December 2003, the PUCT certified that the REPs in the TCC and TNC service territories had reached the 40% threshold for the small commercial class. As a result, TCC and TNC reversed $6 million and $3 million, respectively, of retail clawback regulatory liabilities previously accrued for the small commercial class. Based upon customer information filed by the nonaffiliated company which operates as the PTB REP for TCC and TNC, TCC and TNC updated their estimated residential retail clawback regulatory liability. At December 31, 2004, TCCs recorded retail clawback regulatory liability was $61 million and TNCs was $14 million. TCC and TNC each recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $32 million and $7 million, respectively, for their share of the retail clawback liability.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the True-up Proceeding. In October 2004, the PUCT issued a final order which resulted in an over-recovery balance of $4 million. TNC had adjusted its deferred fuel balance in 2003 by $20 million and in 2004 by $10 million in compliance with the final PUCT order. Challenges to that order were filed in December 2004 in federal and state district courts.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery fuel balance for inclusion in the True-up Proceeding. TCC provided for disallowances increasing its deferred fuel over-recovery liability by $81 million in 2003 and $62 million in 2004. On February 24, 2005, the PUCT in its open meeting increased the over-recovery by approximately $2 million, inclusive of interest, for imputed capacity. TCC has provided for a $212 million deferred over-recovery fuel balance at December 31, 2004, which does not include the $2 million disallowance ruled by the PUCT. However, management is unable to predict the amount, if any, of any additional disallowances of TCCs final fuel over-recovery balance which will be included in its True-up Proceeding until a final order is issued. Management believes it has materially provided for probable to date disallowances in TCCs final fuel proceeding pending receipt of an order.

See TCC Fuel Reconciliation and TNC Fuel Reconciliations in Note 4 for further discussion.

Carrying Costs on Net True-up Regulatory Assets

In December 2001, the PUCT issued a rule concerning stranded cost True-up Proceedings stating, among other things, that carrying costs on stranded costs would begin to accrue on the date that the PUCT issued its final order in the True-up Proceeding. TCC and one other Texas electric utility company filed a direct appeal of the rule to the Texas Third Court of Appeals contending that carrying costs should commence on January 1, 2002, the day that retail customer choice began in ERCOT.

The Third Court of Appeals ruled against the utilities, who then appealed to the Texas Supreme Court. On June 18, 2004, the Texas Supreme Court reversed the decision of the Third Court of Appeals determining that a carrying cost should be accrued beginning January 1, 2002 and remanded the proceeding to the PUCT for further consideration. The Supreme Court determined that utilities with stranded costs are not permitted to over-recover stranded costs and ordered that the PUCT should address whether any portion of the 2002 and 2003 wholesale capacity auction true-up regulatory asset includes a recovery of stranded costs or carrying costs on stranded costs. A motion for rehearing with the Supreme Court was denied and the ruling became final.

In the CenterPoint Order, the PUCT addressed the Supreme Courts remand decision and specified the manner in which carrying costs should be calculated. In December 2004, TCC computed, based on its interpretation of the methodology contained in the CenterPoint Order, carrying costs of $470 million for the period January 1, 2002 through December 31, 2004 on its stranded generation plant costs net of excess earnings and its wholesale capacity auction true-up regulatory assets at the 11.79% overall pretax cost of capital rate in its UCOS rate proceeding. The embedded 8.12% debt component of the carrying cost of $302 million ($225 million on stranded generation plant costs and $77 million on wholesale capacity auction true-up) was recognized in income in December 2004. This amount is included in Carrying Costs on Stranded Cost Recovery in TCCs Consolidated Statements of Income. Of the $302 million recorded in 2004, approximately $109 million, $105 million and $88 million related to the years 2004, 2003 and 2002, respectively. The remaining equity component of $168 million will be recognized in income as collected.

TCC will continue to accrue a carrying cost at the rate set forth above until it recovers its approved net true-up regulatory asset. The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until one year after a final order is issued in the fuel proceeding or a final order is issued in TCCs True-up Proceeding, whichever comes first. At that time, a carrying cost will begin to accrue on the deferred fuel. For all remaining true-up items, including the retail clawback, a carrying cost will begin to accrue when a final order is issued in TCCs True-up Proceeding. If the PUCT further adjusts TCCs net true-up regulatory asset in TCCs True-up Proceeding, the carrying cost will also be adjusted.

Stranded Cost Recovery

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through nonbypassable transition charges and competition transition charges in the regulated T&D rates. TCC will seek to securitize the approved net stranded generation costs plus related carrying costs. The annual costs of the resultant securitization bonds will be recovered through a nonbypassable transition charge collected by the T&D utility over the term of the securitization bonds. The other approved net true-up items will be recovered or refunded over time through a nonbypassable competition transition wires charge or credit inclusive of a carrying cost.

TCCs recorded net true-up regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.6 billion at December 31, 2004. The securitizable portion of this net true-up regulatory asset, which consists of net stranded generation costs plus related carrying costs, was $1.4 billion at December 31, 2004. We expect that TCCs True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net true-up regulatory asset through December 31, 2004. The PUCT will review TCCs filing and determine the amount for the recoverable net true-up regulatory assets.

Due to differences between CenterPoints and TCCs facts and circumstances, the lack of direct applicability of certain portions of the CenterPoint Order to TCC and the unknown nature of future developments in TCCs True-up Proceeding, we cannot, at this time, determine if TCC will incur disallowances in its True-up Proceeding in excess of the $185 million provided in December 2004.

Management believes that TCCs recorded net true-up regulatory asset at December 31, 2004 is in compliance with the Texas Restructuring Legislation, and the applicable portions of the CenterPoint Order and other nonaffiliated true-up orders, and management intends to seek vigorously its recovery. If, however, management determines that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and is able to estimate the amount of such nonrecovery, TCC will record a provision for such amount, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from managements interpretation of the Texas Restructuring Legislation and their evaluation of the applicable portions of the CenterPoint and other true-up orders, additional material disallowances are possible.

TNC 2004 True-up Filing

In June 2004, TNC filed its True-up Proceeding which included the fuel reconciliation balance and the retail clawback calculation. The amount of the deferred over-recovered fuel balance at December 31, 2004 was approximately $4 million. TNC filed an update to its true-up filing to reflect the final order in its fuel reconciliation proceeding. The retail clawback regulatory liability included in the filing was adjusted in 2004 to $14 million, reflecting the number of customers served on January 1, 2004. In January 2005, intervenors filed testimony recommending that TNCs over-recovery be increased by up to approximately $2 million. In addition, they recommended that TNCs excess earnings be increased by approximately $5 million for carrying charges and its T&D rates be reduced by a maximum amount of approximately $3 million on an annual basis to reflect the return on excess earnings approved by the PUCT for the period 1999 through 2001. TNC does not agree with the intervenors reconciliation and filed rebuttal testimony. Management believes it has materially provided for all probable to date disallowances in TNCs True-up Proceeding.

MICHIGAN RESTRUCTURING - *Affecting I&M*

Customer choice commenced for I&Ms Michigan customers on January 1, 2002. Effective with that date the rates on I&Ms Michigan customers bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&Ms total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2004, none of I&Ms customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&Ms Michigan service territory. As a result, management has concluded that as of December 31, 2004 the requirements to apply SFAS 71 continue to be met since I&Ms rates for generation in Michigan continue to be cost-based regulated.

VIRGINIA RESTRUCTURING - *Affecting APCo*

In April 2004, the Governor of Virginia signed legislation that extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004.

ARKANSAS RESTRUCTURING - *Affecting SWEPCo*

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCos Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition.

WEST VIRGINIA RESTRUCTURING - *Affecting APCo*

In 2000, the Public Service Commission of West Virginia (WVPSC) issued an order approving an electricity restructuring plan, which the West Virginia Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the West Virginia legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the West Virginia Legislature failed to enact the required legislation that would allow the

WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the West Virginia Legislature again failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCos outside counsel advised us that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSCs jurisdiction and rate authority over APCos West Virginia generation. As a result, in March 2003 management concluded that deregulation of APCos West Virginia generation business was no longer probable and operations in West Virginia met the requirements to reapply SFAS 71. Reapplying SFAS 71 in West Virginia had an insignificant effect on 2003 results of operations and financial condition.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to perfect its complaint in the pending litigation. The NOV expands the number of alleged modifications undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, eight Northeastern States filed a separate complaint containing the same allegations against the Conesville and Amos plants that the judge disallowed in the pending case. AEP subsidiaries filed an answer to the complaint in January 2005, denying the allegations and stating their defenses.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not routine maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial was scheduled for July 2004, but has been postponed to facilitate further settlement discussions.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, a nonaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is routine maintenance, repair, or replacement and on whether or not a significant net emissions increase results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is routine within the relevant source category in determining if it is routine. Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals. The District Court denied the Federal EPAs motion. On April 13, 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that eliminated the need for a trial, but preserving plaintiffs right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals. The case is fully briefed and oral argument was heard on February 3, 2005.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged CAA violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and in May 2004, that petition was denied.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which AEP subsidiaries are members, to reopen petitions for review of the 1980 and 1992 CAA rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case. Briefing continues in this case and oral argument was held in January 2005.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines routine maintenance repair and replacement to include functionally equivalent equipment replacement. Under the new rule, replacement of a component within an integrated industrial operation (defined as a process unit) with a new component that is identical or functionally equivalent will be deemed to be a routine replacement if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and was to become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003, twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

In December 2000, Cinergy Corp., a nonaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the CAA. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergys settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlements impact on its jointly-owned facilities and its future results of operations and cash flows.

On July 21, 2004, the Sierra Club issued a notice of intent to file a citizen suit claim against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company for alleged violations of the New Source Review programs at the Stuart Station. CSPCo owns a 26% share of the Stuart Station. On September 21, 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the Stuart Station, and seeking injunctive relief and civil penalties. The owners have filed a motion to dismiss portions of the complaint. Management believes the allegations in the complaint are without merit, and intends to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If AEP subsidiaries do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

Notice of Enforcement and Notice of Citizen Suit - Affecting SWEPCo

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant, but after investigation determined further enforcement action was not warranted and withdrew the notice on January 5, 2005.

SWEPCo has previously reported to the TCEQ deviations related to the receipt of off-specification fuel at Knox Lee, the volatile organic compound emissions at Pirkey, and the referenced recordkeeping and reporting requirements and heat input value at Welsh. We have submitted additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims - Affecting AEP System

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

NUCLEAR

Nuclear Plants - Affecting I&M and TCC

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement, I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability - Affecting I&M and TCC

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurers financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2005 with increases in required third party financial protection for nuclear incidents.

SNF Disposal - Affecting I&M and TCC

Federal law provides for government responsibility for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $229 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2004, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal - Affecting I&M and TCC

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low-level radioactive waste accumulation disposal costs for Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2004, 2003 and 2002.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. In May 2004, an updated decommissioning study was completed for STP. The study estimates TCCs share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of approximately $8 million per year. As discussed in Note 10, TCC is in the process of selling its ownership interest in STP to two nonaffiliates, and upon completion of the sale, it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2004 and $12 million in both 2003 and 2002 related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCCs nuclear decommissioning trust asset and liability are included in held for sale amounts on its Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments - Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The AEP System has substantial construction commitments to support its operations. The following table shows the estimated construction expenditures by company for 2005 including amounts for proposed environmental rules:

		(in millions)
AEGCo	$	19.9
APCo		696.7
CSPCo		193.9
I&M		322.8
KPCo		56.1
OPCo		765.6
PSO		126.2
SWEPCo		200.9
TCC		208.5
TNC		73.9

Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

AEP subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2010 for APCo, 2008 for CSPCo, 2014 for I&M, 2008 for KPCo, 2012 for OPCo, 2007 for PSO and 2012 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

I&M has a unit contingent contract to supply approximately 250 MW of capacity to a nonaffiliated entity through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses *- Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC*

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility - Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP has subleased the Facility to the Dow Chemical Company (Dow) under a 5-year term with three 5-year renewal terms for a total term of up to 20 years. The Facility is a Dow-operated qualifying cogeneration facility for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW).

OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000, (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purpose of the PPA began April 2, 2004.

On September 5, 2003, TEM and OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleges that TEM has breached the PPA, and is seeking a determination of OPCos rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of OPCos breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. However, OPCo has entered into an agreement with an affiliate that eliminates OPCos market exposure related to the PPA. The corporate parent of TEM (Tractebel SA) has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the creation of protocols was not subject to arbitration, but did not rule upon the merits of TEMs claim that the PPA is not enforceable. On January 21, 2005, the District Court granted OPCo partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA. The litigation is in the discovery phase, with trial scheduled to begin in March 2005.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the Commercial Operations Date. Despite OPCos prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCos tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the District Court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

Merger Litigation - Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be physically interconnected and confined to a single area or region. In January 2005, a hearing was held before an ALJ. We expect an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy -Affecting APCo, CSPCo, I&M, KPCo and OPCo

In 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enrons bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enrons bankruptcy.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEPs offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. AEP asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. The parties are currently in nonbinding, court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enrons claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and managements analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on results of operations, cash flows or financial condition.

Texas Commercial Energy, LLP Lawsuit - Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four AEP subsidiaries, including TCC and TNC, certain nonaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial courts decision to the United States Court of Appeals for the Fifth Circuit.

Coal Transportation Dispute - Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, have disputed transportation costs for coal received between July 2000 and the present time. The joint plant has remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded a provision for possible loss in December 2004. The provision was deferred as a regulatory asset under PSOs fuel mechanism and affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

FERC Long-term Contracts - Affecting AEP East and AEP West Companies

In 2002, the FERC held a hearing related to a complaint filed by certain wholesale customers located in Nevada. The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were high-priced. The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities had filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJs decision. The utilities request for a rehearing was denied. The utilities appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

8. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered subsequent to December 31, 2002 in accordance with FIN 45 Guarantors Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

Certain Registrant Subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries ordinary course of business. At December 31, 2004, the maximum future payments of the LOCs include $44 million, $1 million, $51 million, $4 million and $43 million for CSPCo, I&M, OPCo, SWEPCo and TCC, respectively, with maturities ranging from March 2005 to April 2007. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCos total future maximum payment exposure is approximately $53 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2004, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine.

Indemnifications and Other Guarantees

All of the Registrant Subsidiaries enter into certain types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant Subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and 2003, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary except for TCC which entered an indemnification of $129 million relating to the sale of its generation assets in July 2004 (see Texas Plants - TCC and TNC Generation Assets section of Note 10). There are no material liabilities recorded for any indemnifications entered during 2004 or 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Registrant Subsidiaries are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East and West companies and for activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2004, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Maximum Potential Loss		
Subsidiary		**(in millions)**
APCo	$	5
CSPCo		2
I&M		3
KPCo		1
OPCo		4
PSO		4
SWEPCo		4
TCC		6
TNC		3

9. <u>SUSTAINED EARNINGS IMPROVEMENT INITIATIVE</u>

In response to difficult conditions in AEPs business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

The Registrant Subsidiaries recorded termination benefits expense relating to 389 terminated employees totaling $57.9 million pretax in the fourth quarter of 2002. Of this amount, the Registrant Subsidiaries paid $5.0 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2004 or 2003. The remaining SEI related payments were made in 2003. The termination benefits expense is classified as Other Operation expense on the Registrant Subsidiaries statements of operations. Management determined that the termination of the employees under the SEI initiative did not constitute a plan curtailment of any of the retirement benefit plans.

The following table shows the staff reductions, termination benefits expense and the remaining termination benefits expense accrual as of December 31, 2002:

	Total Number of Terminated Employees	Total Expense Recorded in 2002 (in millions)		Total Termination Benefits Accrued at December 31, 2002 (in millions)	
AEGCo	-	$	0.3	$	0.3
APCo	93		13.1		12.2
CSPCo	19		5.0		4.5
I&M	146		15.0		13.1
KPCo	16		2.6		2.5
OPCo	33		7.5		7.1
PSO	17		3.1		3.0
SWEPCo	8		3.3		3.1
TCC	37		6.0		5.5
TNC	20		2.0		1.6

10. DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

DISPOSITIONS

2004

Texas Plants - TCC and TNC Generation Assets

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability-must-run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOTs approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOTs 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, a pretax write-down of utility assets of approximately $34 million was recorded in Asset Impairments expense during the third quarter of 2002 on TNCs Statements of Operations. The decision to deactivate the TCC plants resulted in a pretax write-down of utility assets of approximately $96 million, which was deferred and recorded in Regulatory Assets during the third quarter of 2002 in TCCs Consolidated Balance Sheets.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional pretax asset impairment charge to Asset Impairments expense of $4 million in the fourth quarter of 2002. In addition, TNC recorded related inventory write-downs of $3 million ($1 million of fuel inventory in Fuel for Electric Generation expense and $1 million of materials and supplies recorded in Other Operation expense). Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in Regulatory Assets Designated for Securitization in the fourth quarter of 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in Regulatory

Assets.

The total Texas plant pretax asset impairment of $38 million in 2002 related to TNC is included in Asset Impairments expense in TNCs Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as reliability-must-run status.

During the fourth quarter of 2003, after receiving indicative bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale - Texas Generation Plants on TCCs Consolidated Balance Sheets. In accordance with Texas Restructuring Legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding. As a result of the True-up Proceeding, if TCC is unable to recover all or a portion of its requested costs (see Net Stranded Generation Costs section of Note 6), any unrecovered costs could have a material adverse effect on TCCs results of operations, cash flows and possibly financial condition.

In March 2004, TCC signed an agreement to sell eight natural gas plants, one coal-fired plant and one hydro plant to a nonrelated joint venture. The sale was completed in July 2004 for approximately $428 million, net of adjustments. The sale did not have a significant effect on TCCs results of operations during the period ending December 31, 2004.

In December 2004, TCC recorded a $185 pretax deduction ($121 net of tax) related to the TCC true-up regulatory asset for stranded generation plant costs (see Net Stranded Generation Costs section of Note 6). This deduction is shown as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax on TCCs 2004 Consolidated Statements of Income.

The remaining generation assets and liabilities of TCC are classified as Assets of Discontinued Operations and Held for Sale and Liabilities of Discontinued Operations and Held for Sale, respectively, on TCCs Consolidated Balance Sheets.

2003

Water Heater Assets - APCo, CSPCo, I&M, KPCo and OPCo

APCo, CSPCo, I&M, KPCo and OPCo participated in a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. We sold our water heater rental program and recorded a pretax loss in the first quarter of 2003 based upon final terms of the sale agreement. We provided for pretax charges in the fourth quarter of 2002 based on an estimated sales price. See below for amounts by company:

Subsidiary Company	**Asset Impairment Charge Recorded in Fourth Quarter 2002 (Pretax)**	**Lease Prepayment Penalty Recorded in Fourth Quarter 2002 (Pretax)**	**Loss on Sale Recorded in First Quarter 2003 (Pretax)**
		(in millions)	
APCo	$ 0.050	$ 0.062	$ 0.056
CSPCo	0.615	0.758	0.740
I&M	0.643	0.792	0.787
KPCo	0.011	0.011	0.011
OPCo	1.757	2.163	2.165

Ft. Davis Wind Farm - TNC

In the 1990s, TNC developed a 6 MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002, TNCs engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility was completed in 2004. An estimated pretax loss on abandonment of $5 million was recorded in December 2002. The loss was recorded in Asset Impairments on TNCs Statements of Operations.

ASSETS HELD FOR SALE

Texas Plants - Oklaunion Power Station

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million, subject to closing adjustments, to an unrelated party. In May 2004, TCC received notice from the two nonaffiliated co-owners of the Oklaunion Power Station announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, TCC entered into sales agreements with both of its nonaffiliated co-owners for the sale of TCCs 7.81% ownership of the Oklaunion Power Station. One of these agreements is currently being challenged in Dallas County, Texas State District Court by the unrelated party with which TCC entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners exercise of their rights of first refusal void. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its future results of operations. TCCs assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale - Texas Generation Plants and Liabilities Held for Sale - Texas Generation Plants, respectively, in TCCs Consolidated Balance Sheets.

Texas Plants - South Texas Project

In February 2004, TCC signed an agreement to sell its 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, TCC received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, TCC entered into sales agreements with two of its nonaffiliated co-owners for the sale of TCCs 25.2% share of the STP nuclear plant. TCC does not expect the sale to have a significant effect on its future results of operations. TCC expects the sale to close in the first six months of 2005. TCCs assets and liabilities related to STP have been classified as Assets Held for Sale - Texas Generation Plants and Liabilities Held for Sale - Texas Generation Plants, respectively, in TCCs Consolidated Balance Sheets as of December 31, 2004 and 2003.

The assets and liabilities of the entities held for sale at December 31, 2004 and 2003 are as follows:

	Texas Plants (TCC)	
	December 31,	
	2004	2003
	(in millions)	
Assets:		
Current Assets	$ 24	$ 57
Property, Plant and Equipment, Net	413	797
Regulatory Assets	48	49
Nuclear Decommissioning Trust Fund	143	125
Total Assets Held for Sale - Texas Generation Plants	$ 628	$ 1,028
Liabilities:		
Regulatory Liabilities - Other	$ 1	$ 9
Asset Retirement Obligations	249	219
Total Liabilities Held for Sale - Texas Generation Plants	$ 250	$ 228

ASSETS HELD AND USED

Blackhawk Coal Company - I&M

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting managements decision not to pursue development of potential gas reserves. As a result, a pretax charge of $10 million was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Nonoperating Expenses in I&Ms Consolidated Statements of Income.

11. <u>BENEFIT PLANS</u>

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and life insurance benefits for retired employees in the U.S. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004 (see FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003 section of Note 2). The Medicare subsidy reduced the FAS 106 accumulated postretirement benefit obligation (APBO) related to benefits attributed to past service by $202 million contributing to an actuarial gain in 2004. The tax-free subsidy reduced 2004s net periodic postretirement benefit cost by a total of $29 million, including $12 million of amortization of the actuarial gain, $4 million of reduced service cost, and $13 million of reduced interest cost on the APBO.

The following table provides the reduction in the net periodic postretirement cost for 2004 for the Registrant Subsidiaries:

Postretirement Benefit Cost Reduction

		(in thousands)
APCo	$	5,208
CSPCo		2,417
I&M		3,647
KPCo		690
OPCo		4,106
PSO		1,520
SWEPCo		1,571
TCC		1,849
TNC		770

The following tables provide a reconciliation of the changes in the plans projected benefit obligations and fair value of assets over the two-year period ending at the plans measurement date of December 31, 2004, and a statement of the funded status as of December 31 for both years:

Pension Obligations, Plan Assets, Funded Status as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004 (in millions)	2003
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 3,688	$ 3,583	$ 2,163	$ 1,877
Service Cost	86	80	41	42
Interest Cost	228	233	117	130
Participant Contributions	-	-	18	14
Actuarial (Gain) Loss	379	91	(130)	192
Benefit Payments	(273)	(299)	(109)	(92)
Projected Obligation at December 31	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,180	$ 2,795	$ 950	$ 723
Actual Return on Plan Assets	409	619	98	122
Company Contributions (a)	239	65	136	183
Participant Contributions	-	-	18	14
Benefit Payments (a)	(273)	(299)	(109)	(92)
Fair Value of Plan Assets at December 31	$ 3,555	$ 3,180	$ 1,093	$ 950
Funded Status:				
Funded Status at December 31	$ (553)	$ (508)	$ (1,007)	$ (1,213)
Unrecognized Net Transition Obligation	-	2	179	206
Unrecognized Prior Service Cost (Benefit)	(9)	(12)	5	6
Unrecognized Net Actuarial Loss	1,040	797	795	977
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

(a) AEPs contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Amounts Recognized in the Balance Sheet as of December 31, 2004 and 2003:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	2003	2004 (in millions)	2003
Prepaid Benefit Costs	$ 524 (a)	$ 325	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(28)	(24)
Additional Minimum Liability	(566)	(723)	N/A	N/A
Intangible Asset	36	39	N/A	N/A
Pretax Accumulated Other Comprehensive Income	530	684	N/A	N/A
Net Asset (Liability) Recognized	$ 478	$ 279	$ (28)	$ (24)

N/A = Not Applicable

(a) Includes $386 million related to the qualified plan that became fully funded upon receipt of the December 2004 discretionary contribution.

Pension and Other Postretirement Plans Assets:

The asset allocations for AEPs pension plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category, are as follows:

	Target Allocation	**Percentage of Plan Assets at Year End**	
	2005	**2004**	**2003**
Asset Category		**(in percentages)**	
Equity Securities	70	68	71
Debt Securities	28	25	27
Cash and Cash Equivalents	2	7	2
Total	100	100	100

The asset allocations for AEPs other postretirement benefit plans at the end of 2004 and 2003, and target allocation for 2005, by asset category, are as follows:

	Target Allocation	**Percentage of Plan Assets at Year End**	
	2005	**2004**	**2003**
Asset Category		**(in percentages)**	
Equity Securities	70	70	61
Debt Securities	28	28	36
Other	2	2	3
Total	100	100	100

AEPs investment strategy for their employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation when considered appropriate. Because of a $200 million discretionary contribution at the end of 2004, the actual pension asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced to the target allocation in January 2005.

The value of AEPs pension plans assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The qualified plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits).

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation:

	2004	2003
	(in millions)	
Qualified Pension Plans	$ 3,918	$ 3,549
Nonqualified Pension Plans	80	76
Total	$ 3,998	$ 3,625

Minimum Pension Liability:

AEPs combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $553 million at December 31, 2004. For AEPs underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2004 and 2003 were as follows:

	Underfunded Pension Plans	
End of Year	2004	2003
	(in millions)	
Projected Benefit Obligation	$ 2,978	$ 3,688
Accumulated Benefit Obligation	2,880	3,625
Fair Value of Plan Assets	2,406	3,180
Accumulated Benefit Obligation Exceeds theFair Value of Plan Assets	474	445

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2004	2003
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

AEP made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intends to make additional discretionary contributions of approximately $100 million per quarter in 2005 to meet its goal of fully funding all qualified pension plans by the end of 2005.

Actuarial Assumptions for Benefit Obligations:

The weighted-average assumptions as of December 31, used in the measurement of AEPs benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	2004	**2003**	**2004**	**2003**
			(in percentages)	
Discount Rate	5.50	6.25	5.80	6.25
Rate of Compensation Increase	3.70	3.70	N/A	N/A

The method used to determine the discount rate that AEP utilizes for determining future benefit obligations was revised in 2004. Historically, it has been based on the Moodys AA bond index which includes long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, AEP changed to a duration based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for pension plans and 5.80% for other postretirement benefit plans.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Estimated Future Benefit Payments and Contributions:

Information about the expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

	Pension Plans		Other Postretirement Benefit Plans	
Employer Contributions	**2005**	**2004**	**2005**	**2004**
			(in millions)	
Required Contributions (a)	$17	$31	N/A	N/A
Additional Discretionary Contributions	400 (b)	200 (b)	$142	$137

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor.

(b) Contribution in 2004 and expected contribution in 2005 in excess of the required contribution to fully fund AEPs qualified pension plans by the end of 2005.

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater, plus the additional discretionary contributions to fully fund the qualified pension plans. The contribution to the other postretirement benefit plans trust is generally based on the amount of the other postretirement benefit plans expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The table below reflects the total benefits expected to be paid from the plan or from AEPs assets, including both AEPs share of the benefit cost and the participants share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2005	$ 293	$ 115	$ -
2006	302	122	(9)
2007	317	131	(10)
2008	327	140	(11)
2009	348	151	(12)
Years 2010 to 2014, in Total	1,847	867	(72)

Components of Net Periodic Benefit Cost:

The following table provides the components of AEPs net periodic benefit cost (credit) for the plans for fiscal years 2004, 2003 and 2002:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
			(in millions)			
Service Cost	$ 86	$ 80	$ 72	$ 41	$ 42	$ 34
Interest Cost	228	233	241	117	130	114
Expected Return on Plan Assets	(292)	(318)	(337)	(81)	(64)	(62)
Amortization of Transition (Asset) Obligation	2	(8)	(9)	28	28	29
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial (Gain) Loss	17	11	(10)	36	52	27
Net Periodic Benefit Cost (Credit)	40	(3)	(44)	141	188	142
Capitalized Portion	(10)	(3)	15	(46)	(43)	(26)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 30	$ (6)	$ (29)	$ 95	$ 145	$ 116

Net Pension Cost by Registrant:

The following table provides the net periodic benefit cost (credit) for the plans by the following Registrant Subsidiaries for fiscal years 2004, 2003 and 2002:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
				(in thousands)		
APCo	$ 1,272	$ (5,202)	$ (9,988)	$ 25,783	$ 33,682	$ 25,153
CSPCo	(1,626)	(5,399)	(8,328)	11,050	14,684	11,494
I&M	4,460	(812)	(4,149)	17,259	22,999	17,608
KPCo	571	(566)	(1,405)	2,961	4,043	2,986
OPCo	(128)	(6,621)	(11,327)	21,038	28,208	22,654
PSO	2,795	(291)	(3,708)	8,449	9,885	8,436
SWEPCo	3,602	1,018	(2,162)	8,400	10,264	8,371
TCC	2,987	(123)	(4,560)	10,144	12,951	10,733
TNC	1,351	606	(993)	4,280	5,875	4,798

Actuarial Assumptions for Net Periodic Benefit Costs:

The weighted-average assumptions as of January 1, used in the measurement of AEPs benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2004	2003	2002	2004	2003	2002
				(in percentages)		
Discount Rate	6.25	6.75	7.25	6.25	6.75	7.25
Expected Return on Plan Assets	8.75	9.00	9.00	8.35	8.75	8.75
Rate of Compensation Increase	3.70	3.70	3.70	N/A	N/A	N/A

The expected return on plan assets for 2004 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The health care trend rate assumptions used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	2004	2003
Initial	10.0 %	10.0 %
Ultimate	5.0 %	5.0 %

Year Ultimate Reached	2009	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 27	$ (21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	302	(245)

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. Prior to January 1, 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participated in two large AEP sponsored defined contribution retirement savings plans. The contributions to the plan are 75% of the first 6% of eligible employee compensation.

The following table provides the cost for contributions to the retirement savings plans by the following Registrant Subsidiaries for fiscal years 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
APCo	$ 6,538	$ 6,450	$ 6,722
CSPCo	2,723	2,745	2,784
I&M	7,262	7,616	8,039
KPCo	1,030	1,042	1,043
OPCo	5,688	5,719	5,785
PSO	2,731	2,350	2,260
SWEPCo	3,571	3,418	3,170
TCC	2,544	2,757	3,054
TNC	1,126	1,332	1,574

Other UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UWMA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by AEP and benefits are paid from AEPs general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2004, 2003 and 2002.

12. BUSINESS SEGMENTS

All of AEPs Registrant Subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, an electricity generation business. All of the Registrant Subsidiaries other activities are insignificant. The Registrant Subsidiaries operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

13. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. However, energy markets are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contracts term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant Subsidiaries accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Contracts that have been designated as normal purchase or normal sale under SFAS 133 are not considered derivatives and are recognized on the accrual or settlement basis.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on if the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Registrant Financial Statements. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses in the Consolidated Statements of Operations depending on the relevant facts and circumstances.

The Registrant Subsidiaries designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), Registrant Subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Registrant Financial Statements during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) and subsequently reclassify it to Revenues in the Registrant Financial Statements when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change.

Fair Value Hedging Strategies

Certain Registrant Subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure.

The interest rate forward and swap transactions effectively modify exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant Subsidiaries do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

Certain Registrant Subsidiaries enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. Registrant Subsidiaries do not hedge all foreign currency exposure.

Certain Registrant Subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify exposure to interest risk by converting a portion of floating-rate debt to a fixed rate. During 2004, certain Registrant Subsidiaries also entered into various forward starting interest rate swap contracts to manage the interest rate exposure on anticipated borrowings of fixed-rate debt through the second quarter of 2005. The anticipated debt offerings have a high probability of occurrence because the proceeds will be utilized to fund existing debt maturities as well as fund projected capital expenditures. Registrant Subsidiaries do not hedge all interest rate exposure. During 2004, APCO and I&M reclassified immaterial amounts to earnings because the original forecasted transaction did not occur within the originally specified time period.

Registrant Subsidiaries enter into, and designate as cash flow hedges, certain forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. Registrant Subsidiaries do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity. During 2004, certain Registrant Subsidiaries classified immaterial amounts into earnings as a result of hedge ineffectiveness related to cash flow hedging strategies.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2002, 2003 and 2004:

	(in thousands)		
APCo			
Beginning Balance at December 31, 2001	$	(340	)
Effective portion of changes in fair value		(1,310	)
Reclasses from AOCI to net income		(270	)
Balance at December 31, 2002		(1,920	)
Effective portion of changes in fair value		(448	)
Reclasses from AOCI to net income		799	
Balance at December 31, 2003		(1,569	)
Effective portion of changes in fair value		(6,269	)
Reclasses from AOCI to net income		(1,486	)
Ending Balance, December 31, 2004	$	(9,324	)
CSPCo			
Beginning Balance at December 31, 2001	$	-	
Effective portion of changes in fair value		62	
Reclasses from AOCI to net income		(329	)
Balance at December 31, 2002		(267	)
Effective portion of changes in fair value		194	
Reclasses from AOCI to net income		275	
Balance at December 31, 2003		202	
Effective portion of changes in fair value		2,304	
Reclasses from AOCI to net income		(1,113	)

Ending Balance, December 31, 2004	$	1,393	
I&M			
Beginning Balance at December 31, 2001	$	(3,835	)
Effective portion of changes in fair value		34	
Reclasses from AOCI to net income		3,515	
Balance at December 31, 2002		(286	)
Effective portion of changes in fair value		209	
Reclasses from AOCI to net income		299	
Balance at December 31, 2003		222	
Effective portion of changes in fair value		(3,141	)
Reclasses from AOCI to net income		(1,157	)
Ending Balance, December 31, 2004	$	(4,076	)
KPCo			
Beginning Balance at December 31, 2001	$	(1,903	)
Effective portion of changes in fair value		343	
Reclasses from AOCI to net income		1,882	
Balance at December 31, 2002		322	
Effective portion of changes in fair value		75	
Reclasses from AOCI to net income		23	
Balance at December 31, 2003		420	
Effective portion of changes in fair value		918	
Reclasses from AOCI to net income		(525	)
Ending Balance, December 31, 2004	$	813	
OPCo			
Beginning Balance at December 31, 2001	$	(196	)
Effective portion of changes in fair value		(103	)
Reclasses from AOCI to net income		(439	)
Balance at December 31, 2002		(738	)
Effective portion of changes in fair value		256	
Reclasses from AOCI to net income		379	
Balance at December 31, 2003		(103	)
Effective portion of changes in fair value		2,830	
Reclasses from AOCI to net income		(1,486	)
Ending Balance, December 31, 2004	$	1,241	
PSO			
Beginning Balance at December 31, 2001	$	-	
Effective portion of changes in fair value		2	
Reclasses from AOCI to net income		(44	)
Balance at December 31, 2002		(42	)
Effective portion of changes in fair value		18	
Reclasses from AOCI to net income		180	
Balance at December 31, 2003		156	
Effective portion of changes in fair value		713	
Reclasses from AOCI to net income		(469	)
Ending Balance, December 31, 2004	$	400	
SWEPCo			
Beginning Balance at December 31, 2001	$	-	
Effective portion of changes in fair value		1	
Reclasses from AOCI to net income		(49	)
Balance at December 31, 2002		(48	)
Effective portion of changes in fair value		21	
Reclasses from AOCI to net income		211	
Balance at December 31, 2003		184	
Effective portion of changes in fair value		(450	)
Reclasses from AOCI to net income		(554	)
Ending Balance, December 31, 2004	$	(820	)
TCC			
Beginning Balance at December 31, 2001	$	-	
Effective portion of changes in fair value		30	
Reclasses from AOCI to net income		(66	)
Balance at December 31, 2002		(36	)

Effective portion of changes in fair value		(1,931)
Reclasses from AOCI to net income		139
Balance at December 31, 2003		(1,828)
Effective portion of changes in fair value		866
Reclasses from AOCI to net income		1,619
Ending Balance, December 31, 2004	$	657
TNC		
Beginning Balance at December 31, 2001	$	-
Effective portion of changes in fair value		3
Reclasses from AOCI to net income		(18)
Balance at December 31, 2002		(15)
Effective portion of changes in fair value		(641)
Reclasses from AOCI to net income		55
Balance at December 31, 2003		(601)
Effective portion of changes in fair value		373
Reclasses from AOCI to net income		513
Ending Balance, December 31, 2004	$	285

The following table approximates net gains from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2004 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is fourteen months.

		(in thousands)
APCo	$	1,876
CSPCo		1,750
I&M		1,386
KPCo		800
OPCo		2,083
PSO		1,182
SWEPCo		1,413
TCC		825
TNC		357

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of significant financial instruments for Registrant Subsidiaries at December 31, 2004 and 2003 are summarized in the following tables.

	2004		2003	
	Book Value	Fair Value	Book Value	Fair Value
		(in thousands)		
AEGCo				

Long-term Debt	$ 44,820	$ 46,249	$ 44,811	$ 47,882
APCo				
Long-term Debt	1,784,598	1,822,687	1,864,081	1,926,518
Cumulative Preferred Stock Subject to Mandatory Redemption	-	-	5,360	5,287
CSPCo				
Long-term Debt	987,626	1,040,885	897,564	938,595
I&M				
Long-term Debt	1,312,843	1,349,614	1,339,359	1,400,937
Cumulative Preferred Stock Subject to Mandatory Redemption	61,445	61,637	63,445	63,293
KPCo				
Long-term Debt	508,310	521,776	487,602	503,704
OPCo				
Long-term Debt	2,011,060	2,092,645	2,039,940	2,117,131
Cumulative Preferred Stock Subject to Mandatory Redemption	5,000	5,016	7,250	7,214
PSO				
Long-term Debt	546,092	557,630	574,298	589,956
SWEPCo				
Long-term Debt	805,369	833,246	884,308	917,982
TCC				
Long-term Debt	1,907,294	2,013,546	2,291,625	2,393,468
TNC				
Long-term Debt	314,357	329,514	356,754	374,420

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments are classified as available for sale for decommissioning (I&M, TCC) and SNF disposal for I&M. I&M reports trusts in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on its Consolidated Balance Sheets. TCC reports trusts in Assets Held for Sale - Texas Generating Plants on its Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	I&M		**TCC**	
	2004	**2003**	**2004**	**2003**
		(in thousands)		
Fair Value	$ 1,053,400	$ 982,400	$ 143,200	$ 124,700
Cost Basis	936,500	900,000	107,000	94,800

	I&M			**TCC**		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
			(in thousands)			
Net Unrealized Holding Gain (Loss)	$ 34,500	$ 35,500	$ (25,400)	$ 6,400	$ 16,700	$ (7,500)

14. <u>INCOME TAXES</u>

The details of the Registrant Subsidiaries income taxes before extraordinary loss and cumulative effect of accounting changes as reported are are as follows:

Year Ended December 31, 2004	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 5,729	$ 34,721	$ 54,287	$ 79,645	$ (4,697)
Deferred	(2,187)	55,347	17,945	(1,784)	14,925
Deferred Investment Tax Expense(Credits)	-	1,010	(2,864)	(7,476)	(1,233)
Total	3,542	91,078	69,368	70,385	8,995
Charged (Credited) to Nonoperating Income (net):					
Current	(287)	2,968	2,853	4,994	1,827
Deferred	(32)	(7,762)	(4,550)	(3,764)	(2,151)
Deferred Investment Tax Credits	(3,339)	(1,173)	-	-	-
Total	(3,658)	(5,967)	(1,697)	1,230	(324)
Total Income Tax as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671

Year Ended December 31, 2004	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 69,576	$ (12,315)	$ 26,618	$ 117,667	$ 16,693
Deferred	30,080	23,226	14,166	(86,034)	5,272
Deferred Investment Tax Credits	(2,498)	(1,791)	(4,326)	(4,736)	(1,292)
Total	97,158	9,120	36,458	26,897	20,673
Charged (Credited) to Nonoperating Income (net):					
Current	6,307	(119)	(347)	5,637	2,872
Deferred	(6,751)	(1,192)	(1,384)	102,524	(1,036)
Deferred Investment Tax Credits	(604)	-	-	-	-
Total	(1,048)	(1,311)	(1,731)	108,161	1,836
Total Income Tax as Reported	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509

Year Ended December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 7,481	$ 84,449	$ 83,469	$ 58,190	$ (7,840)
Deferred	(5,838)	37,024	3,982	66	21,183
Deferred Investment Tax Credits	-	(1,884)	(3,041)	(7,330)	(1,168)
Total	1,643	119,589	84,410	50,926	12,175
Charged (Credited) to Nonoperating Income (net):					
Current	(196)	(646)	(2,183)	5,283	(1,382)
Deferred	-	(12,461)	(8,496)	(14,960)	(1,076)
Deferred Investment Tax Credits	(3,354)	(1,262)	(69)	(101)	(42)
Total	(3,550)	(14,369)	(10,748)	(9,778)	(2,500)
Total Income Tax as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2003					
Charged (Credited) to Operating Expenses (net):					
Current	$ 116,316	$ 55,834	$ 51,564	$ 88,530	$ 33,822
Deferred	32,191	(17,036)	7,230	14,769	(5,113)
Deferred Investment Tax Credits	(2,493)	(1,790)	(4,326)	(5,207)	(1,520)
Total	146,014	37,008	54,468	98,092	27,189
Charged (Credited) to Nonoperating Income (net):					
Current	708	(1,566)	(6,108)	2,456	1,454
Deferred	(7,709)	2,395	2,712	4,624	1,620
Deferred Investment Tax Credits	(614)	-	-	-	-
Total	(7,615)	829	(3,396)	7,080	3,074
Total Income Tax as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2002					
Charged (Credited) to Operating Expenses (net):					
Current	$ 6,607	$ 99,140	$ 81,538	$ 66,063	$ 680
Deferred	(5,028)	17,626	25,771	(19,870)	9,451
Deferred Investment Tax Expense(Credits)	2	(3,229)	(3,095)	(7,340)	(1,173)
Total	1,581	113,537	104,214	38,853	8,958
Charged (Credited) to Nonoperating Income (net):					
Current	(173)	(354)	9,442	3,435	1,583
Deferred	-	(849)	(2,479)	2,949	388
Deferred Investment Tax Credits	(3,363)	(1,408)	(174)	(400)	(67)
Total	(3,536)	(2,611)	6,789	5,984	1,904
Total Income Tax as Reported	$ (1,955)	$ 110,926	$ 111,003	$ 44,837	$ 10,862

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2002					
Charged (Credited) to Operating Expenses (net):					
Current	$ 86,026	$ (49,673)	$ 41,354	$ 30,494	$ 109
Deferred	30,048	75,659	(3,134)	113,726	(10,652)
Deferred Investment Tax Credits	(2,493)	(1,791)	(4,524)	(5,206)	(1,271)
Total	113,581	24,195	33,696	139,014	(11,814)
Charged (Credited) to Nonoperating Income (net):					
Current	2,732	(1,812)	1,772	3,223	1,334
Deferred	15,962	-	-	(71)	(1,623)
Deferred Investment Tax Credits	(684)	-	-	-	-
Total	18,010	(1,812)	1,772	3,152	(289)
Total Income Tax as Reported	$ 131,591	$ 22,383	$ 35,468	$ 142,166	$ (12,103)

Shown below is a reconciliation for each Registrant Subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2004					
Net Income	$ 7,842	$ 153,115	$ 140,258	$ 133,222	$ 25,905
Income Taxes	(116)	85,111	67,671	71,615	8,671
Pretax Income	$ 7,726	$ 238,226	$ 207,929	$ 204,837	$ 34,576
Income Tax on Pretax Income at Statutory Rate (35%)	$ 2,704	$ 83,379	$ 72,775	$ 71,693	$ 12,102
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	808	10,719	2,570	19,023	1,466
Nuclear Fuel Disposal Costs	-	-	-	(3,338)	-
Allowance for Funds Used During Construction	(1,060)	(3,948)	(515)	(3,160)	(603)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(1,632)	(336)	(2,974)	(1,497)
Investment Tax Credits (net)	(3,339)	(163)	(2,864)	(7,476)	(1,233)
State and Local Income Taxes	933	6,629	159	7,102	(197)
Other	(536)	(9,873)	(4,118)	(9,652)	(1,367)
Total Income Taxes as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671
Effective Income Tax Rate	N.M.	35.7 %	32.5 %	35.0 %	25.1 %

N.M. = Not Meaningful

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2004					
Net Income	$ 210,116	$ 37,542	$ 89,457	$ 174,122	$ 47,659
Extraordinary Loss	-	-	-	120,534	-
Income Taxes	96,110	7,809	34,727	135,058	22,509
Pretax Income	$ 306,226	$ 45,351	$ 124,184	$ 429,714	$ 70,168
Income Tax on Pretax Income at Statutory Rate (35%)	$ 107,179	$ 15,873	$ 43,464	$ 150,400	$ 24,559
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,977	(937)	(1,622)	(812)	(739)
Investment Tax Credits (net)	(3,102)	(1,791)	(4,326)	(4,736)	(1,292)
State and Local Income Taxes	305	1,882	4,736	543	2,762
Other	(13,249)	(7,218)	(7,525)	(10,337)	(2,781)
Total Income Taxes as Reported	$ 96,110	$ 7,809	$ 34,727	$ 135,058	$ 22,509
Effective Income Tax Rate	31.4 %	17.2 %	28.0 %	31.4 %	32.1 %

	AEGCo	APCo	CSPCo	I&M	KPCo

(in thousands)

Year Ended December 31, 2003					
Net Income	$ 7,964	$ 280,040	$ 200,430	$ 86,388	$ 32,330
Cumulative Effect of Accounting Changes	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	(1,907)	105,220	73,662	41,148	9,675
Pretax Income	$ 6,057	$ 308,003	$ 246,809	$ 130,696	$ 43,139
Income Tax on Pretax Income at Statutory Rate (35%)	$ 2,120	$ 107,801	$ 86,383	$ 45,744	$ 15,099
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	371	9,209	2,220	17,735	1,538
Nuclear Fuel Disposal Costs	-	-	-	(6,465)	-
Allowance for Funds Used During Construction	(1,053)	(2,048)	(232)	(4,127)	(851)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(2,280)	(7)	(693)	(735)
Investment Tax Credits (net)	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
State and Local Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	(737)	(5,439)	(8,518)	(8,646)	(4,108)
Total Income Taxes as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675
Effective Income Tax Rate	N.M.	34.2 %	29.8 %	31.5 %	22.4 %

	OPCo	**PSO**	**SWEPCo**	**TCC**	**TNC**
			(in thousands)		
Year Ended December 31, 2003					
Net Income	$ 375,663	$ 53,891	$ 98,141	$ 217,669	$ 58,557
Cumulative Effect of Accounting Changes	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	138,399	37,837	51,072	105,172	30,263
Pretax Income	$ 389,430	$ 91,728	$ 140,696	$ 322,719	$ 85,926
Income Tax on Pretax Income at Statutory Rate (35%)	$ 136,301	$ 32,105	$ 49,244	$ 112,952	$ 30,074
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,096	(467)	(390)	(957)	(214)
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State and Local Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	(3,608)	5,104	(3,179)	8,818	(1,154)
Total Income Taxes as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263
Effective Income Tax Rate	35.5 %	41.2 %	36.3 %	32.6 %	35.2 %

N.M. = Not Meaningful

	AEGCo	**APCo**	**CSPCo**	**I&M**	**KPCo**
			(in thousands)		
Year Ended December 31, 2002					
Net Income	$ 7,552	$ 205,492	$ 181,173	$ 73,992	$ 20,567
Income Taxes	(1,955)	110,926	111,003	44,837	10,862
Pretax Income	$ 5,597	$ 316,418	$ 292,176	$ 118,829	$ 31,429

Income Tax on Pretax Income at Statutory Rate (35%)	$ 1,959	$ 110,746	$ 102,262	$ 41,590	$ 11,000
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	286	3,082	2,899	21,812	2,057
Nuclear Fuel Disposal Costs	-	-	-	(3,087)	-
Allowance for Funds Used During Construction	(1,136)	-	-	(3,453)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(735)
Investment Tax Credits (net)	(3,361)	(4,637)	(3,270)	(7,740)	(1,240)
State and Local Income Taxes	335	6,469	11,387	124	1,058
Other	(412)	(4,734)	(2,275)	(4,409)	(1,278)
Total Income Taxes as Reported	$ (1,955)	$ 110,926	$ 111,003	$ 44,837	$ 10,862
Effective Income Tax Rate	N.M.	35.1 %	38.0 %	37.7 %	34.6 %

	OPCo	**PSO**	**SWEPCo**	**TCC**	**TNC**
			(in thousands)		
Year Ended December 31, 2002					
Net Income	$ 220,023	$ 41,060	$ 82,992	$ 275,941	$ (13,677)
Income Taxes	131,591	22,383	35,468	142,166	(12,103)
Pretax Income	$ 351,614	$ 63,443	$ 118,460	$ 418,107	$ (25,780)
Income Tax on Pretax Income at Statutory Rate (35%)	$ 123,065	$ 22,205	$ 41,461	$ 146,337	$ (9,023)
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	4,227	(583)	(2,790)	(295)	(32)
Investment Tax Credits (net)	(3,177)	(1,791)	(4,524)	(5,207)	(1,271)
State and Local Income Taxes	18,051	2,639	3,987	2,202	(1,577)
Other	(10,575)	(87)	(2,666)	(871)	(200)
Total Income Taxes as Reported	$ 131,591	$ 22,383	$ 35,468	$ 142,166	$ (12,103)
Effective Income Tax Rate	37.4 %	35.3 %	29.9 %	34.0 %	46.9 %

N.M. = Not Meaningful

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each Registrant Subsidiary:

	AEGCo	**APCo**	**CSPCo**	**I&M**	**KPCo**
			(in thousands)		
Year Ended December 31, 2004					
Deferred Tax Assets	$ 65,740	$ 238,784	$ 98,848	$ 650,596	$ 39,511
Deferred Tax Liabilities	(90,502)	(1,091,320)	(563,393)	(966,326)	(267,047)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)
Property Related Temporary Differences	$ (58,895)	$ (680,324)	$ (385,426)	$ (71,771)	$ (169,452)
Amounts Due From Customers For Future Federal Income Taxes	6,266	(94,438)	(5,652)	(34,260)	(25,112)

Deferred State Income Taxes	(5,050)	(106,817)	(25,658)	(48,830)	(32,099)
Transition Regulatory Assets	-	(8,914)	(54,852)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	43,978	32,747	24,366	4,725
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	33,967	-	-	22,600	-
Accrued Nuclear Decommissioning Expense	-	-	-	(188,428)	-
Deferred Fuel and Purchased Power	-	20,245	(39)	(19)	-
Accrued Pensions	-	(8,306)	(12,528)	6,135	(768)
Provision for Refund	-	809	-	(73)	-
Nuclear Fuel	-	-	-	(15,485)	-
All Other (Net)	(1,050)	(18,769)	(13,137)	(9,965)	(4,830)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2004					
Deferred Tax Assets	$ 165,891	$ 76,411	$ 70,039	$ 248,456	$ 33,063
Deferred Tax Liabilities	(1,109,356)	(460,501)	(469,795)	(1,495,567)	(171,528)
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)
Property Related Temporary Differences	$ (781,479)	$ (331,428)	$ (341,306)	$ (390,709)	$ (132,383)
Amounts Due From Customers For Future Federal Income Taxes	(55,121)	7,687	5,927	7,513	4,552
Deferred State Income Taxes	(78,060)	(59,598)	(44,074)	(42,693)	(7,705)
Transition Regulatory Assets	(79,480)	-	(153)	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,853)	-
Deferred Income Taxes on Other Comprehensive Loss	39,989	(40)	635	188	69
Deferred Fuel and Purchased Power	-	(126)	(10,274)	(1,738)	(8,554)
Accrued Pensions	(7,963)	(30,463)	(26,219)	(38,836)	(16,432)
Provision for Refund	-	67	1,915	51,838	11,513
Deferred Book Gain	-	-	-	71,749	-
Regulatory Assets	-	-	(581)	(580,736)	2,886
Securitized Transition Assets	-	-	-	(257,612)	-
All Other (Net)	18,649	29,811	14,374	3,854	7,589
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2003					
Deferred Tax Assets	$ 79,545	$ 237,873	$ 122,453	$ 695,037	$ 44,413
Deferred Tax Liabilities	(103,874)	(1,041,228)	(580,951)	(1,032,413)	(256,534)
Net Deferred Tax Liabilities	$ (24,329)	$ (803,355)	$ (458,498)	$ (337,376)	$ (212,121)
Property Related Temporary Differences	$ (62,271)	$ (623,126)	$ (357,980)	$ (74,501)	$ (151,404)
Amounts Due From Customers For Future Federal Income Taxes	6,949	(94,457)	(5,575)	(37,233)	(23,203)
Deferred State Income Taxes	(4,350)	(87,484)	(26,972)	(45,736)	(33,535)

Transition Regulatory Assets	-	(10,799)	(66,002)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	28,047	24,946	13,519	3,345
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	36,916	-	-	24,563	-
Accrued Nuclear Decommissioning Expense	-	-	-	(173,054)	-
Deferred Fuel and Purchased Power	-	24,047	(273)	(19)	496
Deferred Cook Plant Restart Costs	-	-	-	(20,064)	-
Accrued Pensions	-	(8,019)	(13,000)	(2,832)	(1,006)
Provision for Refund	-	809	-	(73)	-
Nuclear Fuel	-	-	-	(7,027)	-
All Other (Net)	(1,573)	(32,373)	(13,642)	(14,919)	(6,814)
Net Deferred Tax Liabilities	$ (24,329)	$ (803,355)	$ (458,498)	$ (337,376)	$ (212,121)

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2003					
Deferred Tax Assets	$ 192,026	$ 164,801	$ 163,457	$ 298,648	$ 67,794
Deferred Tax Liabilities	(1,125,608)	(500,235)	(512,521)	(1,543,560)	(180,813)
Net Deferred Tax Liabilities	$ (933,582)	$ (335,434)	$ (349,064)	$ (1,244,912)	$ (113,019)
Property Related Temporary Differences	$ (721,118)	$ (297,809)	$ (321,082)	$ (698,554)	$ (118,876)
Amounts Due From Customers For Future Federal Income Taxes	(55,143)	8,728	8,259	8,330	5,402
Deferred State Income Taxes	(80,573)	(56,413)	(33,651)	(42,044)	(2,946)
Transition Regulatory Assets	(109,150)	-	-	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,470)	-
Nuclear Fuel	-	-	-	(7,240)	-
Deferred Income Taxes on Other Comprehensive Loss	26,280	23,607	23,644	33,316	14,387
Deferred Fuel and Purchased Power	12	(8,460)	(10,996)	(1,738)	(10,143)
Accrued Pensions	(9,222)	(16,088)	(12,922)	(20,054)	(9,961)
Provision for Refund	-	67	3,000	29,823	7,601
Regulatory Assets	-	-	-	(199,945)	4,577
Securitized Transition Assets	-	-	-	(281,260)	-
All Other (Net)	15,332	10,934	(5,316)	4,000	(3,060)
Net Deferred Tax Liabilities	$ (933,582)	$ (335,434)	$ (349,064)	$ (1,244,912)	$ (113,019)

The IRS and other taxing authorities routinely examine the Registrant Subsidiaries tax returns. Management believes that the Registrant Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. Theses positions relate to the timing and amount of income, deductions and the computation of the tax liability. Registrant Subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. Registrant Subsidiaries have received Revenue Agents Reports from the IRS for the years 1991 through 1999, and have filed protests contesting certain proposed adjustments. CSW, which was a separate consolidated group prior to its merger with AEP, is currently being audited for the years 1997 through the date of the merger in June 2000. Returns for the years 2000 through 2003 are presently being audited by the IRS.

Although the outcome of tax audits is uncertain, in managements opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As ofDecember 31, 2004, Registrant Subsidiaries have total provisions for uncertain tax positions of approximately$23 million, excluding AEGCo. In addition,the Registrant Subsidiaries accrue interest on theseuncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP Systems current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

15. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2004			(in thousands)		
Lease Payments on Operating Leases	$ 75,545	$ 6,832	$ 5,313	$ 111,344	$ 1,416
Amortization of Capital Leases	92	7,906	3,933	6,825	1,605
Interest on Capital Leases	7	1,260	705	1,403	258
Total Lease Rental Costs	$ 75,644	$ 15,998	$ 9,951	$ 119,572	$ 3,279

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2004			(in thousands)		
Lease Payments on Operating Leases	$ 14,390	$ 3,697	$ 4,877	$ 3,949	$ 1,458
Amortization of Capital Leases	8,232	520	3,543	437	216
Interest on Capital Leases	2,259	53	2,054	66	27
Total Lease Rental Costs	$ 24,881	$ 4,270	$ 10,474	$ 4,452	$ 1,701

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2003			(in thousands)		
Lease Payments on Operating Leases	$ 76,322	$ 6,148	$ 5,277	$ 111,923	$ 1,258
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951
Interest on Capital Leases	-	1,123	899	1,276	148
Total Lease Rental Costs	$ 76,591	$ 16,488	$ 11,074	$ 120,569	$ 3,357

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003			(in thousands)		

Lease Payments on Operating Leases	$ 40,034	$ 4,883	$ 4,708	$ 6,360	$ 2,132
Amortization of Capital Leases	9,437	174	1,434	161	83
Interest on Capital Leases	2,472	17	899	16	9
Total Lease Rental Costs	$ 51,943	$ 5,074	$ 7,041	$ 6,537	$ 2,224

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2002			(in thousands)		
Lease Payments on Operating Leases	$ 76,143	$ 6,634	$ 5,209	$ 112,037	$ 1,597
Amortization of Capital Leases	238	9,729	6,010	8,319	2,171
Interest on Capital Leases	19	2,240	1,717	2,221	469
Total Lease Rental Costs	$ 76,400	$ 18,603	$ 12,936	$ 122,577	$ 4,237

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2002			(in thousands)		
Lease Payments on Operating Leases	$ 80,210	$ 4,403	$ 3,240	$ 7,184	$ 1,981
Amortization of Capital Leases	12,637	-	-	-	-
Interest on Capital Leases	4,501	-	-	-	-
Total Lease Rental Costs	$ 97,348	$ 4,403	$ 3,240	$ 7,184	$ 1,981

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2004			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,339	$ 1,759	$ 7,104	$ 22,917	$ 797
Distribution	-	-	-	14,589	-
Other	353	45,892	21,270	43,478	10,405
Total Property, Plant and Equipment	12,692	47,651	28,374	80,984	11,202
Accumulated Amortization	218	27,709	15,884	30,252	6,839
Net Property, Plant and EquipmentUnder Capital Leases	$ 12,474	$ 19,942	$ 12,490	$ 50,732	$ 4,363
Obligations Under Capital Leases:					
Noncurrent Liability	$ 12,264	$ 13,136	$ 8,660	$ 44,608	$ 2,802
Liability Due Within One Year	210	6,742	3,854	6,124	1,561
Total Obligations Under Capital Leases	$ 12,474	$ 19,878	$ 12,514	$ 50,732	$ 4,363

Year Ended December 31, 2004	OPCo	PSO	SWEPCo	TCC	TNC
	(in thousands)				
Property, Plant and Equipment Under Capital Leases:					
Production	$ 34,796	$ -	$ 14,269	$ -	$ -
Distribution	-	-	-	-	-
Other	46,131	1,813	53,620	1,364	780
Total Property, Plant and Equipment	80,927	1,813	67,889	1,364	780
Accumulated Amortization	41,187	529	33,343	484	246
Net Property, Plant and Equipment Under Capital Leases	$ 39,740	$ 1,284	$ 34,546	$ 880	$ 534
Obligations Under Capital Leases:					
Noncurrent Liability	$ 31,652	$ 747	$ 30,854	$ 468	$ 314
Liability Due Within One Year	9,081	537	3,692	412	220
Total Obligations Under Capital Leases	$ 40,733	$ 1,284	$ 34,546	$ 880	$ 534

Year Ended December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
	(in thousands)				
Property, Plant and Equipment Under Capital Leases:					
Production	$ 865	$ 2,758	$ 7,104	$ 4,492	$ 1,138
Distribution	-	-	-	14,589	-
Other	-	55,640	25,345	52,536	11,562
Total Property, Plant and Equipment	865	58,398	32,449	71,617	12,700
Accumulated Amortization	596	33,036	16,828	33,774	7,408
Net Property, Plant and Equipment Under CapitalLeases	$ 269	$ 25,362	$ 15,621	$ 37,843	$ 5,292
Obligations Under Capital Leases:					
Noncurrent Liability	$ 182	$ 16,134	$ 11,397	$ 31,315	$ 3,549
Liability Due Within One Year	87	9,218	4,221	6,528	1,743
Total Obligations Under Capital Leases	$ 269	$ 25,352	$ 15,618	$ 37,843	$ 5,292

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
	(in thousands)				
Property, Plant and Equipment Under Capital Leases :					
Production	$ 21,099	$ -	$ -	$ -	$ -
Distribution	-	-	-	-	-
Other	53,752	1,176	52,695	1,204	556
Total Property, Plant and Equipment	74,851	1,176	52,695	1,204	556

Accumulated Amortization	40,565	166	31,153	160	83
Net Property, Plant and Equipment Under CapitalLeases	$ 34,286	$ 1,010	$ 21,542	$ 1,044	$ 473
Obligations Under Capital Leases:					
Noncurrent Liability	$ 25,064	$ 558	$ 18,383	$ 636	$ 270
Liability Due Within One Year	9,624	452	3,159	407	203
Total Obligations Under Capital Leases	$ 34,688	$ 1,010	$ 21,542	$ 1,043	$ 473

Future minimum lease payments consisted of the following at December 31, 2004:

Capital Leases	**AEGCo**	**APCo**	**CSPCo**	**I&M**	**KPCo**
			(in thousands)		
2005	$ 990	$ 7,988	$ 4,468	$ 8,367	$ 1,854
2006	980	6,192	3,184	6,895	1,195
2007	972	3,512	2,178	4,733	962
2008	964	3,060	2,100	4,342	519
2009	962	1,053	1,131	6,734	184
Later Years	17,997	1,060	931	25,348	169
Total Future Minimum Lease Payments	22,865	22,865	13,992	56,419	4,883
Less Estimated Interest Element	10,391	2,987	1,478	5,687	520
Estimated Present Value of FutureMinimum Lease Payments	$ 12,474	$ 19,878	$ 12,514	$ 50,732	$ 4,363

Capital Leases	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**TNC**
			(in thousands)		
2005	$ 9,795	$ 579	$ 6,160	$ 456	$ 242
2006	9,295	413	6,057	300	140
2007	7,093	211	5,892	120	59
2008	5,061	99	5,832	71	44
2009	3,392	44	5,445	18	41
Later Years	20,332	33	20,513	-	59
Total Future Minimum Lease Payments	54,968	1,379	49,899	965	585
Less Estimated Interest Element	14,235	95	15,353	85	51
Estimated Present Value of FutureMinimum Lease Payments	$ 40,733	$ 1,284	$ 34,546	$ 880	$ 534

Noncancelable Operating Leases	AEGCo	APCo	CSPCo	I&M	KPCo
	(in thousands)				
2005	$ 73,955	$ 7,126	$ 5,670	$ 104,003	$ 1,475
2006	73,938	6,126	3,212	98,883	1,150
2007	73,934	4,554	2,720	96,330	982
2008	73,933	3,624	2,089	95,529	741
2009	73,932	2,982	1,755	94,630	595
Later Years	960,341	6,354	3,188	1,019,602	1,792
Total Future Minimum Lease Payments	$ 1,330,033	$ 30,766	$ 18,634	$ 1,508,977	$ 6,735

Noncancelable Operating Leases	OPCo	PSO	SWEPCo	TCC	TNC
	(in thousands)				
2005	$ 16,220	$ 5,760	$ 6,793	$ 5,751	$ 2,200
2006	15,005	4,877	6,786	4,117	1,860
2007	14,448	4,409	7,979	3,456	1,497
2008	13,893	2,334	8,917	2,694	1,315
2009	13,410	2,139	8,176	2,377	1,440
Later Years	71,888	6,777	10,614	6,276	3,053
Total Future Minimum Lease Payments	$ 144,864	$ 26,296	$ 49,265	$ 24,671	$ 11,365

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and previously leased it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($470 million). Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for as an operating lease. For 2002 and the first half of 2003, operating lease payments related to the Gavin Scrubber were recorded as operating lease expense by OPCo. After July 1, 2003, OPCo records the depreciation, interest and other operating expenses of JMG and eliminates JMGs rental revenues against OPCos operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of the requirement to consolidate JMG and there was no change in net income due to the consolidation of JMG. The debt obligations of JMG are now included in long-term debt as Notes Payable and Installment Purchase Contracts and are excluded from the above table of future minimum lease payments.

At any time during the obligation, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year term is noncancelable. At the end of the initial term, OPCo can renew the obligation, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In the case of a sale at less than the adjusted acquisition cost, OPCo is required to pay the difference to JMG.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company as of December 31, 2004 are $1.3 billion.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

16. FINANCING ACTIVITIES

Dividend Restrictions

Under PUHCA, Registrant Subsidiaries can only pay dividends out of retained or current earnings.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Balance Sheet. The investment in the trust is reported as Other Investments within Other Property and Investments while the Junior Subordinated Debentures are reported as Notes Payable to Trust within Long-term Debt.

In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are due October 1, 2043. Junior Subordinated Debentures were retired in the second quarter of 2004 for PSO and in the third quarter of 2004 for TCC. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2004 and 2003:

Business Trust	Security	Units Issued/ Outstanding at 12/31/04	Amount in Other Investments at 12/31/04 (a)	Amount in Notes Payable to Trust at 12/31/04 (b)	Amount in Other Investments at 12/31/03 (a)	Amount in Notes Payable to Trust at 12/31/03 (b)	Description of Underlying Debentures of Registrant
				(in millions)			
CPL Capital I	8.00%, Series A	-	$ -	$ -	$ 5	$ 141	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	-	-	-	2	77	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	3	113	SWEPCo, $113 million, 5.25% 5-year fixed rate period, Series B
Total		110,000	$ 3	$ 113	$ 10	$ 331	

(a) Amounts are in Other Investments within Other Property and Investments.

(b) Amounts are in Notes Payable to Trust within Long-term Debt.

Each of the business trusts is treated as a nonconsolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under the subordinated debentures, the parent company has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit - AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2007 for short-term borrowings sufficient to fund the Utility Money Pool and the Nonutility Money Pool as well as its own requirements in an amount not to exceed $7.2 billion. The Utility Money Pool participants money pool activity and corresponding SEC authorized limits for the year ended December 31, 2004 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31, 2004	SEC Authorized Short-Term Borrowing Limit
			(in thousands)			
AEGCo	$ 56,525	$ 932	$ 23,532	$ 731	$ (26,915)	$ 125,000
APCo	211,060	32,575	76,100	13,501	(211,060)	600,000
CSPCo	29,687	184,962	12,808	75,580	141,550	350,000
I&M	216,528	70,363	89,578	29,290	5,093	500,000
KPCo	44,749	41,501	13,580	15,282	16,127	200,000
OPCo	81,862	297,136	29,578	152,442	125,971	600,000
PSO	145,619	35,158	47,099	16,204	(55,002)	300,000
SWEPCo	71,252	107,966	38,073	64,386	39,106	350,000
TCC	109,696	427,414	62,494	120,312	(207)	600,000
TNC	16,136	110,430	6,704	41,500	51,504	250,000

Maximum, minimum and average interest rates for funds loaned to and borrowed from the Utility Money Pool during 2004 are summarized in the following table:

Company	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
			(in percentages)			
AEGCo	2.24	0.89	1.97	1.78	1.47	1.91
APCo	2.24	0.89	1.72	1.23	1.68	1.48
CSPCo	1.88	0.92	2.24	0.89	1.50	1.69
I&M	2.24	0.89	2.23	0.94	1.45	1.93
KPCo	1.92	0.91	2.24	0.89	1.59	1.61
OPCo	1.92	1.18	2.24	0.89	1.29	1.46
PSO	2.23	0.89	2.24	1.29	1.38	1.80
SWEPCo	1.92	0.89	2.24	0.91	1.37	1.67
TCC	2.23	0.91	2.24	0.89	1.40	1.47

TNC	1.50	0.91	2.24	0.89	1.09	1.56

As of December 31, 2004, AEP had credit facilities totaling $2.8 billion to support its commercial paper program. At December 31, 2004, AEP had $23 million in outstanding commercial paper related to JMG Funding. This commercial paper is specifically associated with the Gavin Scrubber as identified in the Gavin Scrubber Financing Arrangement section of Note 15. This commercial paper does not reduce AEPs available liquidity. As of December 31, 2004, AEPs commercial paper outstanding related to the corporate borrowing program was $0. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $661 million in June 2004 and the weighted average interest rate of commercial paper outstanding during the year was 1.81%. On February 10, 2003, Moodys Investor Services downgraded AEPs short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poors Rating Services reaffirmed AEPs A-2 short-term rating for commercial paper. On August 2, 2004, Moodys Investor Services placed AEPs ratings on positive outlook.

Interest expense related to the Utility Money Pool is included in Interest Charges in each of the Registrant Subsidiaries Financial Statements. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
AEGCo	$ 338	$ 289	$ 345
APCo	1,136	147	4,396
CSPCo	32	732	1,771
I&M	1,127	313	196
KPCo	65	897	1,638
OPCo	51	2,332	5,685
PSO	486	1,218	4,114
SWEPCo	217	787	3,118
TCC	177	617	7,773
TNC	8	449	3,242

Interest income related to the Utility Money Pool is included in Nonoperating Income in each of the Registrant Subsidiaries Financial Statements. Interest income earned from amounts advanced to the Utility Money Pool by registrant were:

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
AEGCo	$ 1	$ 8	$ 126
APCo	24	1,589	366
CSPCo	1,076	777	683
I&M	84	1,814	1,260
KPCo	177	-	2
OPCo	1,965	700	-
PSO	76	156	-
SWEPCo	649	662	105
TCC	1,445	589	-
TNC	587	164	-

Outstanding short-term debt for AEP Consolidated consisted of:

	Year Ended December 31,	
	2004	2003
	(in millions)	
Balance Outstanding		
Notes Payable	$ -	$ 18
Commercial Paper - AEP	-	282
Commercial Paper - JMG	23	26
Total	$ 23	$ 326

Sale of Receivables - AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credits balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies receivables, and accelerate its cash collections.

During 2004, AEP Credit renewed its sale of receivables agreement which had expired on August 25, 2004. As a result of the renewal, AEP Credits sale of receivables agreement will now expire on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCos accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31,	
	2004	2003
	(in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,163	$ 5,221
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	80	124
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivables	7	7
Average Variable Discount Rate	1.50 %	1.33 %
Retained Interest if 10% Adverse Change in Uncollectible Accounts	78	122
Retained Interest if 20% Adverse Change in Uncollectible Accounts	76	121

Historical loss and delinquency amount for the AEP Systems customer accounts receivable managed portfolio:

	Face Value			
	Year Ended December 31,			
	2004		2003	
	(in millions)			
Customer Accounts Receivable Retained	$	930	$	1,155
Accrued Unbilled Revenues Retained		592		596
Miscellaneous Accounts Receivable Retained		79		83
Allowance for Uncollectible Accounts Retained		(77)		(124)
Total Net Balance Sheet Accounts Receivable		1,524		1,710
Customer Accounts Receivable Securitized (Affiliate)		435		385
Total Accounts Receivable Managed	$	1,959	$	2,095
Net Uncollectible Accounts Written Off	$	86	$	39

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $25 million and $30 million at December 31, 2004 and 2003, respectively.

Under the factoring arrangement, participating Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each companys receivables and administrative costs. The costs of factoring customer accounts receivable are reported as an operating expense. The amount of factored accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

	December 31,			
	2004		2003	
	(in millions)			
APCo	$	58.7	$	60.2
CSPCo		110.1		100.2
I&M		91.4		93.0
KPCo		34.4		30.4
OPCo		106.0		99.3
PSO		96.7		99.6
SWEPCo		72.0		64.4

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
APCo	$ 3.9	$ 3.4	$ 4.8
CSPCo	10.2	9.8	15.8
I&M	6.5	6.1	7.4
KPCo	2.6	2.4	2.7
OPCo	7.7	8.7	11.4
PSO	8.9	5.8	7.2
SWEPCo	5.8	4.9	5.4
TCC	-	-	2.2
TNC	-	-	1.4

17. RELATED PARTY TRANSACTIONS

For other related party transactions, also see in Note 16 Lines of Credit - AEP System and Sale of Receivables-AEP Credit.

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each companys member-load-ratio, which is calculated monthly on the basis of each companys maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power and Gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition the risk management of electricity, and to a lesser extent gas contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP Systems traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP Systems traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires the AEP West companies to maintain adequate annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverers incremental cost plus a portion of the recipients savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are shared based on the amount of energy each AEP West company contributes that is sold to third parties. Upon sale of its generation assets, TCC will no longer supply generating capacity under the CSW Operating Agreement.

AEPs System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEPs East and West companies zone. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any Registrant Subsidiary is primarily sold to customers (or in the case of the ERCOT area of Texas, REPs) by such Registrant Subsidiary at rates approved (other than in Ohio, Virginia and the ERCOT area of Texas) by the public utility commission in the jurisdiction of sale. In Ohio, Virginia and the ERCOT area of Texas, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation (see Note 6).

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary. See Note 13 for a discussion of the marketing of such power.

AEP East and West Companies Sales and Purchases to the Pools

The following table shows the revenues derived from sales to the pools and direct sales to affiliates for years ended December 31, 2004, 2003 and 2002:

	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
Related Party Revenues			(in thousands)			
2004						
Sales to East System Pool	$ 128,736	$ 60,409	$ 243,105	$ 36,032	$ 497,925	$ -
Direct Sales to East Affiliates	62,018	-	-	-	57,241	241,578
Direct Sales to West Affiliates	22,017	13,190	14,536	5,155	17,721	-
Other	3,792	6,516	3,533	403	8,628	-
Total Revenues	$ 216,563	$ 80,115	$ 261,174	$ 41,590	$ 581,515	$ 241,578

	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
Related Party Revenues			(in thousands)			
2003						
Sales to East System Pool	$ 130,921	$ 59,113	$ 228,667	$ 32,827	$ 503,334	$ -
Sales to West System Pool	27	9	17	6	21	-
Direct Sales to East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales to West Affiliates	27,951	16,428	17,674	6,425	21,759	-
Other	3,256	8,819	2,845	550	8,400	-
Total Revenues	$ 222,793	$ 84,369	$ 249,203	$ 39,808	$ 584,278	$ 232,955

	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
Related Party Revenues			(in thousands)			
2002						
Sales to East System Pool	$ 106,651	$ 42,986	$ 197,525	$ 22,369	$ 397,248	$ -
Sales to West System Pool	18,300	12,107	13,036	4,717	16,265	-
Direct Sales to East Affiliates	58,213	-	-	-	50,599	213,071
Direct Sales to West Affiliates	-	-	-	-	-	-
Other	3,313	2,109	3,577	878	1,090	-
Total Revenues	$ 186,477	$ 57,202	$ 214,138	$ 27,964	$ 465,202	$ 213,071

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2004				
Sales to West System Pool	$ 103	$ 521	$ -	$ 159
Direct Sales to East Affiliates	2,652	1,878	188	78
Direct Sales to West Affiliates	3,203	63,141	3,027	71
Other	4,732	5,650	43,824	51,372
Total Revenues	$ 10,690	$ 71,190	$ 47,039	$ 51,680

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2003				
Sales to West System Pool	$ 793	$ 600	$ 15,157	$ 651
Direct Sales to East Affiliates	1,159	706	677	6
Direct Sales to West Affiliates	17,855	64,802	23,248	1,929
Other	3,323	2,746	114,486	52,567
Total Revenues	$ 23,130	$ 68,854	$ 153,568	$ 55,153

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2002				
Sales to West System Pool	$ 674	$ 1,334	$ 18,416	$ 1,280
Direct Sales to East Affiliates	611	270	366	(23)
Direct Sales to West Affiliates	6,047	75,674	956,751	228,404
Other	2,107	(4,949)	32,911	10,764
Total Revenues	$ 9,439	$ 72,329	$ 1,008,444	$ 240,425

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2004, 2003, and 2002:

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2004					
Purchases from East System Pool	$ 370,038	$ 346,463	$ 102,760	$ 68,072	$ 84,042
Direct Purchases from East Affiliates	-	-	169,103	72,475	4,334
Direct Purchases from West Affiliates	915	539	589	211	979
Total Purchases	$ 370,953	$ 347,002	$ 272,452	$ 140,758	$ 89,355

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2003					
Purchases from East System Pool	$ 348,899	$ 335,916	$ 109,826	$ 71,259	$ 88,962

Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
Direct Purchases from West Affiliates	765	471	505	182	625
Total Purchases	$ 351,210	$ 337,323	$ 274,400	$ 141,690	$ 90,821

	APCo	CSPCo	I&M	KPCo	OPCo
Related Party Purchases			**(in thousands)**		
2002					
Purchases from East System Pool	$ 233,677	$ 309,999	$ 83,918	$ 68,846	$ 70,338
Purchases from West System Pool	337	219	237	86	297
Direct Purchases from East Affiliates	583	387	149,569	64,070	519
Total Purchases	$ 234,597	$ 310,605	$ 233,724	$ 133,002	$ 71,154

	PSO	SWEPCo	TCC	TNC
Related Party Purchases		**(in thousands)**		
2004				
Purchases from East System Pool	$ 66	$ 177	$ -	$ -
Purchases from West System Pool	49	191	-	568
Direct Purchases from East Affiliates	45,689	24,988	1,984	1,278
Direct Purchases from West Affiliates	58,197	3,698	4,156	3,365
Total Purchases	$ 104,001	$ 29,054	$ 6,140	$ 5,211

	PSO	SWEPCo	TCC	TNC
Related Party Purchases		**(in thousands)**		
2003				
Purchases from East System Pool	$ 639	$ -	$ -	$ -
Purchases from West System Pool	704	741	289	15,467
Direct Purchases from East Affiliates	46,384	28,376	10,238	4,677
Direct Purchases from West Affiliates	61,912	18,087	8,570	19,265
Other	-	710	-	-
Total Purchases	$ 109,639	$ 47,914	$ 19,097	$ 39,409

	PSO	SWEPCo	TCC	TNC
Related Party Purchases		**(in thousands)**		
2002				
Purchases from East System Pool	$ 343	$ -	$ -	$ -
Purchases from West System Pool	874	(456)	1,366	15,475
Direct Purchases from East Affiliates	29,029	17,242	8,236	2,669
Direct Purchases from West Affiliates	59,208	25,236	13,804	19,438
Total Purchases	$ 89,454	$ 42,022	$ 23,406	$ 37,582

The above summarized related party revenues and expenses are reported as consolidated and are presented as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the statements of operations of each AEP Power Pool member. Since all of the above pool members are included in AEPs consolidated results, the above summarized related party transactions are eliminated in total in AEPs consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each companys member-load-ratio.

The following table shows the net charges (credits) allocated among the parties to the Transmission Agreement during the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
APCo	$ (500)	$ -	$ (13,400)
CSPCo	37,700	38,200	42,200
I&M	(40,800)	(39,800)	(36,100)
KPCo	(6,100)	(5,600)	(5,400)
OPCo	9,700	7,200	12,700

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net charges (credits) allocated among parties to the TCA during the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
		(in thousands)	
PSO	$ 8,100	$ 4,200	$ 4,200
SWEPCo	13,800	5,000	5,000
TCC	(12,200)	(3,600)	(3,600)
TNC	(9,700)	(5,600)	(5,600)

AEPs System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEPs East and West companies zones. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

The allocation of transmission costs and revenues and

The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

CSPCo coal purchases from AEP Coal, Inc.

As a result of managements decision to exit our non-core businesses, AEP Coal, Inc. (AEP Coal) was sold in March 2004. During 2004, AEP Coal sold approximately 330,000 tons of coal mined by AEP Coal to CSPCo to be delivered (at CSPCos expense) to the Conesville Plant for a price of $26.15 per ton. In 2003, AEP Coal and CSPCo were parties to a 2003 coal purchase agreement, dated October 15, 2002. The agreement provided for the sale of up to 960,000 tons of coal mined by AEP Coal to be delivered (at CSPCos expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. In 2002, AEP Coal and CSPCo were parties to a 2002 coal purchase agreement, dated February 1, 2002. The agreement provided for the sale of up to 785,000 tons of coal mined by AEP Coal to be delivered (at CSPCos expense) to the Conesville Plant for a price ranging from $24.00 per ton to $27.00 per ton plus quality adjustments. During 2004, 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $9.5 million, $23.9 million and $21 million, respectively.

AEP Coal and CSPCo were parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, AEP Coal transferred coal from railcars into trucks at AEP Coals Muskie Transloading Facility and delivered the coal via trucks to CSPCos Conesville Preparation Plant or CSPCos Power Plant for a rate of $1.25 per ton, $1.25 per ton and $1.03 per ton, in 2004, 2003 and 2002, respectively. During 2004, 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $1.0 million, $3.4 million and $3.5 million, respectively.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the companies as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents Registrant Subsidiaries liabilities at December 31, 2004 and 2003:

	2004	2003
Company	**(in thousands)**	
APCo	$ (23,736)	$ (32,287)
CSPCo	(13,654)	(18,185)
I&M	(15,266)	(19,932)
KPCo	(5,570)	(7,349)
OPCo	(19,065)	(24,055)
Total	$ (77,291)	$ (101,808)

Fuel Agreement between OCPo and National Power Cooperative, Inc

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for the gas plant, which is owned by NPC. The plant went into service in July 2002 and the AEP East companies purchase 100% of the available generating capacity from the plant through December 2005. The related purchases of gas managed by AEPES were as follows:

	Year Ended December 31,		
	2004	2003	2002
Company		(in thousands)	
APCo	$ 1,351	$ 1,546	$ 583
CSPCo	804	936	387
I&M	884	1,000	418
KPCo	315	363	150
OPCo	980	1,234	519
Total	$ 4,334	$ 5,079	$ 2,057

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) for such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement was renegotiated and extended from December 31, 2004 to December 7, 2022.

I&M Barging and Other Services

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as nonoperating income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2004	2003	2002
Company		(in millions)	
I&M - revenues	$ 38.2	$ 31.9	$ 34.3
AEGCo - expense	9.5	8.1	7.8
APCo - expense	13.0	12.3	12.8
KPCo - expense	0.1	0.1	-
OPCo - expense	4.9	4.3	7.9
MEMCo - expense (Nonutility subsidiary of AEP)	10.7	7.1	5.7

AEP Energy Services - expense (Nonutility subsidiary of AEP)	-	-	0.1

MEMCO services provided and received

AEP MEMCO LLC (MEMCO) provides services for barge towing and general and administrative expenses to I&M. The costs are recorded by I&M as nonoperating expenses. For the years ended December 31, 2004, 2003 and 2002, I&M recorded $12.6 million, $8.8 million and $2.6 million, respectively.

I&M provides services for barge towing and general and administrative expenses to MEMCO. The income is recorded by I&M as an offset to nonoperating expense. For the years ended December 31, 2004, 2003 and 2002, I&M recorded $10.7 million, $7.0 million and $5.0 million, respectively.

Gas Purchases from HPL

HPL purchases physical gas in the spot market, which in turn, is sold to certain operating companies at cost for their fuel requirements. The related HPL sales to TCC and TNC are as follows:

	Year Ended December 31,		
	2004 (a)	**2003**	**2002**
Company		**(in thousands)**	
TCC	$ 129,682	$ 195,527	$ 157,346
TNC	45,767	44,197	64,385

(a) In 2004, purchases from Oklaunion along with the HPL purchases described above comprise the total Fuel from Affiliates for Electric Generation as shown on the Registrant Subsidiaries financial statements.

OPCo Indemnification Agreement with AEPR

OPCo has an indemnification agreement with AEPR whereby AEPR holds OPCo harmless from market exposure related to OPCos Power Purchase and Sale Agreement dated November 15, 2000 with Dow Chemical Company. In 2004, AEPR paid OPCo $21.5 million, which is reported in OPCos Nonoperating Income and Nonoperating Expenses on its Consolidated Statements of Income. See Note 7, Power Generation Facility - Affecting OPCo for further discussion.

Purchased Power from Ohio Valley Electric Corporation

The amounts of power purchased by the Registrant Subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP and CSPCo, for the years ended December 31, 2004, 2003 and 2002 were:

	Year Ended December 31,		
	2004	2003	2002
Company		(in thousands)	
APCo	$ 62,101	$ 55,219	$ 53,386
CSPCo	16,724	15,259	14,885
I&M	27,474	25,659	23,282
OPCo	55,052	50,995	50,135

Sales of Property

The Registrant Subsidiaries had sales of electric property for the years ended December 31, 2004, 2003 and 2002 as shown in the following table.

	2004
	(in thousands)
APCo to OPCo	$ 2,992
I&M to APCo	1,630
	2003
	(in thousands)
AEGCo to OPCo	$ 105
APCo to OPCo	1,079
I&M to OPCo	1,492
OPCo to APCo	2,768
OPCo to I&M	1,096
	2002
	(in thousands)
OPCo to I&M	$ 4,768

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

18. JOINTLY-OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly-owned with affiliated and nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each Registrant Subsidiarys proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments are reflected in its balance sheets under utility plant as follows:

Companys Share December 31,

2004	2003

CSPCo	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
			(in thousands)		
W.C. Beckjord Generating Station (Unit No. 6)	12.5 %$	15,531	$ 139	$ 15,455	$ 127
Conesville Generating Station (Unit No. 4)	43.5	85,036	654	82,115	722
J.M. Stuart Generating Station	26.0	209,842	60,535	204,820	50,326
Wm. H. Zimmer Generating Station	25.4	741,043	7,976	707,281	31,249
Transmission	(a)	62,287	3,744	62,061	742
Total	$	1,113,739	$ 73,048	$ 1,071,732	$ 83,166
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6 %$	85,834	$ 345	$ 85,064	$ 518
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2 %$	237,741	$ 2,559	$ 236,116	$ 2,304
Flint Creek Generating Station (Unit No. 1)	50.0	93,887	756	93,309	737
Pirkey Generating Station (Unit No. 1)	85.9	456,730	2,373	454,303	3,125
Total	$	788,358	$ 5,688	$ 783,728	$ 6,166
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8 %$	39,464	$ 271	$ 38,798	$ 252
South Texas Project Generation Station (Units No. 1 and 2)	25.2	2,386,961	2,144	2,386,579	934
Total	$	2,426,425	$ 2,415	$ 2,425,377	$ 1,186
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7 %$	287,198	$ 1,418	$ 285,314	$ 1,351

(a) Varying percentages of ownership.

(b) Included in Assets Held for Sale - Texas Generation Plants on TCCs Consolidated Balance Sheets.

The accumulated depreciation with respect to each Registrant Subsidiarys share of jointly owned facilities is shown below:

	December 31,	
	2004	2003
Company	(in thousands)	
CSPCo	$ 464,136	$ 435,249
PSO	52,679	50,968
SWEPCo	491,269	465,871
TCC (a)	991,410	991,665
TNC	110,763	103,642

(a) Included in Assets Held for Sale - Texas Generation Plants on TCCs Consolidated Balance Sheets.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each Registrant Subsidiary follows:

Quarterly Periods Ended:	**AEGCo**	**APCo**	**CSPCo**	**I&M**	**KPCo**
			(in thousands)		
March 31, 2004					
Operating Revenues	$ 55,282	$ 526,457	$ 362,305	$ 412,186	$ 113,513
Operating Income	1,547	87,397	54,508	56,813	19,214
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,827	65,336	45,119	43,008	11,611
Net Income	1,827	65,336	45,119	43,008	11,611
June 30, 2004					
Operating Revenues	$ 56,348	$ 464,517	$ 358,126	$ 406,802	$ 109,142
Operating Income	1,373	46,082	44,629	42,995	11,605
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,506	21,826	30,755	27,030	4,068
Net Income	1,506	21,826	30,755	27,030	4,068
September 30, 2004					
Operating Revenues	$ 65,303	$ 491,385	$ 391,833	$ 443,660	$ 114,712
Operating Income	2,214	62,690	65,262	67,482	13,479
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,404	38,459	52,570	51,548	6,160
Net Income	2,404	38,459	52,570	51,548	6,160
December 31, 2004					
Operating Revenues	$ 64,855	$ 465,823	$ 321,317	$ 398,932	$ 113,246
Operating Income	1,770	47,841	19,847	28,598	11,023
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,105	27,494	11,814	11,636	4,066
Net Income (Loss)	2,105	27,494	11,814	11,636	4,066

Quarterly Periods Ended:	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**TNC**
			(in thousands)		
March 31, 2004					
Operating Revenues	$ 589,706	$ 207,456	$ 236,160	$ 287,123	$ 104,377
Operating Income	108,359	856	20,197	55,519	17,350

Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	80,164	(9,003)	5,021	29,404	13,096
Net Income (Loss)	80,164	(9,003)	5,021	29,404	13,096
June 30, 2004					
Operating Revenues	$ 533,058	$ 231,623	$ 268,728	$ 269,868	$ 101,052
Operating Income	62,910	16,860	41,528	23,337	10,772
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	38,783	7,391	27,946	(341)	7,751
Net Income (Loss)	38,783	7,391	27,946	(341)	7,751
September 30, 2004					
Operating Revenues	$ 558,116	$ 356,631	$ 330,370	$ 354,609	$ 152,504
Operating Income	80,837	47,202	60,618	67,790	21,895
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	50,685	38,980	47,209	43,012	16,853
Net Income	50,685	38,980	47,209	43,012	16,853
December 31, 2004					
Operating Revenues	$ 555,516	$ 251,811	$ 252,088	$ 263,666	$ 134,212
Operating Income	60,266	10,158	20,835	49,373	11,229
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes (a)	40,484	174	9,281	222,581	9,959
Net Income	40,484	174	9,281	102,047	9,959

(a) See Texas Restructuring and Net Stranded Generation Costs sections of Note 6 for a discussion of net adjustments of stranded costs recorded in the fourth quarter of 2004.

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2003					
Operating Revenues	$ 60,428	$ 536,228	$ 359,205	$ 418,598	$ 112,094
Operating Income	1,851	112,684	55,151	58,990	19,834
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,796	79,153	38,359	30,687	11,021
Net Income	1,796	156,410	65,642	27,527	9,887
June 30, 2003					
Operating Revenues	$ 59,568	$ 444,751	$ 333,071	$ 376,906	$ 95,464
Operating Income	1,514	49,056	43,417	19,229	10,964
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	1,768	14,636	29,331	(1,191)	4,095
Net Income (Loss)	1,768	14,636	29,331	(1,191)	4,095
September 30, 2003					
Operating Revenues	$ 59,008	$ 483,611	$ 397,655	$ 423,004	$ 103,693
Operating Income	1,809	67,134	71,193	56,242	13,097
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,021	45,715	62,825	37,116	6,501
Net Income	2,021	45,715	62,825	37,116	6,501
December 31, 2003					
Operating Revenues	$ 54,161	$ 492,768	$ 341,920	$ 377,088	$ 105,219
Operating Income	2,000	89,937	55,725	51,606	20,849

Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	2,379	63,279	42,632	22,936	11,847
Net Income	2,379	63,279	42,632	22,936	11,847

Quarterly Periods Ended:	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**TNC**
			(in thousands)		
March 31, 2003					
Operating Revenues	$ 590,631	$ 242,662	$ 255,278	$ 428,358	$ 116,262
Operating Income	98,870	13,146	26,044	92,010	9,865
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	68,350	691	10,491	64,437	6,765
Net Income	192,982	691	19,008	64,559	9,836
June 30, 2003					
Operating Revenues	$ 539,386	$ 277,236	$ 281,306	$ 482,446	$ 136,806
Operating Income	79,831	28,715	35,588	96,603	23,243
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	56,277	17,927	20,590	63,587	17,922
Net Income	56,277	17,927	20,590	63,587	17,922
September 30, 2003					
Operating Revenues	$ 565,318	$ 358,575	$ 361,622	$ 485,129	$ 114,455
Operating Income	93,798	43,527	59,229	84,502	17,419
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	70,367	38,090	42,181	66,221	17,347
Net Income	70,367	38,090	42,181	66,221	17,347
December 31, 2003					
Operating Revenues	$ 549,318	$ 224,349	$ 248,636	$ 351,578	$ 98,423
Operating Income	87,168	7,475	29,275	48,425	17,500
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	56,037	(2,817)	16,362	23,302	13,629
Net Income (Loss)	56,037	(2,817)	16,362	23,302	13,452

For each of the Registrant Subsidiaries, (excluding TCC for 2004) there were no significant, nonrecurring events in the fourth quarter of 2004 or 2003.

COMBINED MANAGEMENTS DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants managements discussion and analysis. The information in this section completes the information necessary for managements discussion and analysis of financial condition and results of operations and is meant to be read with (i) Managements Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for AEPs electric subsidiaries comes from AEPs commercial paper program and revolving credit facilities. Proceeds are loaned to the subsidiaries through intercompany notes. AEP and its subsidiaries also operate a money pool to minimize the AEP Systems external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The electric subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from their parent company.

Dividend Restrictions

Under PUHCA, Registrant Subsidiaries can only pay dividends out of retained or current earnings.

Sale of Receivables Through AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. AEP does not have an ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies receivables, and accelerate cash collections.

During 2004, AEP Credit renewed its sale of receivables agreement through August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2004, $435 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain Registrant Subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia jurisdiction, only a portion of APCos accounts receivable are sold to AEP Credit.

Budgeted Construction Expenditures

Construction expenditures for Registrant Subsidiaries for 2005 are:

Projected Construction Expenditures

Company		(in millions)
AEGCo	$	19.9
APCo		696.7
CSPCo		193.9
I&M		322.8
KPCo		56.1
OPCo		765.6
PSO		126.2
SWEPCo		200.9
TCC		208.5
TNC		73.9

Significant Factors

Possible Divestitures

AEPs management is firmly committed to continually evaluating the need to reallocate resources to areas that effectively match investments with our business strategy, providing the greatest potential for financial returns and to disposing of investments that no longer meet these goals.

TCC made progress on its planned divestiture of its generation assets by (1) announcing in June 2004 and September 2004 that it had signed agreements to sell its 7.81% share of the Oklaunion Power Station to two nonaffiliated co-owners of the plant for approximately $43 million, subject to closing adjustments, (2) announcing in September 2004 that it had signed agreements to sell its 25.2% share of the STP nuclear plant to two nonaffiliated co-owners of the plant for approximately $333 million, subject to closing adjustments, and (3) closing in July 2004 on the sale of its remaining generation assets, including eight natural gas plants, one coal-fired plant and one hydro-electric plant for approximately $428 million, net of adjustments. TCC expects the sales of Oklaunion and STP to be completed in the first half of 2005. Nevertheless, there could be potential delays in receiving necessary regulatory approvals and clearances or in resolving litigation with a third party affecting Oklaunion which could delay the closings. TCC will file with the PUCT to recover net stranded costs associated with the sales pursuant to Texas Restructuring Legislation. Stranded costs will be calculated on the basis of all generation assets, not individual plants.

Texas Regulatory Activity - Affecting TCC

Texas Restructuring

Texas Restructuring Legislation enacted in 1999 provides the framework and timetable to allow retail electricity competition.

The Texas Restructuring Legislation, among other things:

- provides for the recovery of net stranded generation costs and other generation true-up amounts through securitization and nonbypassable wires charges,
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility,
- provides for an earnings test for each of the years 1999 through 2001 and,
- provides for a stranded cost True-up Proceeding after January 10, 2004.

The True-up Proceedings will determine the amount and recovery of:

net stranded generation plant costs and net generation-related regulatory assets less any unrefunded excess earnings (net stranded generation costs),

a true-up of actual market prices determined through legislatively-mandated capacity auctions to the projected power costs used in the PUCTs excess cost over market (ECOM) model for 2002 and 2003 (wholesale capacity auction true-up revenues),
excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback),
final approved deferred fuel balance, and
net carrying costs on true-up amounts.

TCCs recorded net true-up regulatory asset for amounts subject to approval in the True-up Proceeding is approximately $1.6 billion at December 31, 2004.

The Texas Restructuring Legislation required utilities with stranded generation plant costs to use market-based methods to value certain generation assets for determining stranded generation plant costs. TCC elected to use the sale of assets method to determine the market value of its generation assets for determining stranded generation plant costs. For purposes of the True-up Proceeding, the amount of stranded generation plant costs under this market valuation methodology will be the amount by which the book value of TCCs generation assets exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets.

In December 2003, based on an expected loss from the sale of its generating assets, TCC recognized as a regulatory asset an estimated impairment of approximately $938 million from the sale of all its generation assets. The impairment was computed based on an estimate of TCCs generation assets sales price compared to book basis at December 31, 2003. On July 1, 2004, TCC completed the sale of most of its coal, gas and hydro plants for approximately $428 million, net of adjustments. The closings of the sales of STP and Oklaunion plants are expected to occur in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals. In addition, there could be delays in resolving litigation with a third party affecting Oklaunion. On February 15, 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closings of the sales of all the generation assets. TCC asked the PUCT to rule on the request in April 2005.

On December 17, 2004, the PUCT also issued an Order on Rehearing in the CenterPoint True-up Proceeding (CenterPoint Order). CenterPoint is a nonaffiliated electric utility in Texas. Among other things, the CenterPoint Order provided certain adjustments to stranded generation plant costs to avoid what the PUCT deemed to be duplicative recovery of stranded costs and the capacity auction true-up amount. The CenterPoint Order also confirmed that stranded costs are to be determined as of December 31, 2001, and identified how carrying costs from that date are to be computed.

In the fourth quarter of 2004, TCC made net adjustments totaling $185 million ($121 million, net of tax) to its stranded generation plant cost regulatory asset. TCC increased this net regulatory asset by $53 million to adjust its estimated impairment loss to a December 31, 2001 book basis (instead of December 31, 2003 book basis), including the reflection of certain PUCT-ordered accelerated amortizations of the STP nuclear plant as of that date. In addition, TCCs stranded generation plant costs regulatory asset was reduced by $238 million based on an applicable PUCT duplicate depreciation adjustment in the CenterPoint Order. These net adjustments are reflected as Extraordinary Loss on Texas Stranded Cost Recovery, Net of Tax in TCCs Consolidated Statements of Income.

In addition to the two items above (the $938 million impairment in 2003 and the $185 million adjustment in 2004), TCC had recorded $121 million of impairments in 2002 and 2003 on its gas-fired plants. Additionally, other miscellaneous items and the costs to complete the sales, which are still ongoing, of $23 million are included in the recoverable stranded generation plant costs of $897 million.

In the CenterPoint Order, the PUCT specified the manner in which carrying costs should be calculated. In December 2004, TCC computed, based on its interpretation of the methodology contained in the CenterPoint Order, carrying costs of $470 million for the period January 1, 2002 through December 31, 2004 on its stranded generation plant costs net of excess earnings and its wholesale capacity auction true-up regulatory assets at the 11.79% overall pretax cost of capital rate in its UCOS rate proceeding. The embedded 8.12% debt component of the carrying cost of $302 million ($225 million on stranded generation plant costs and $77 million on wholesale capacity auction true-up) was recognized in income in December 2004. This amount is included in Carrying Costs on Stranded Cost Recovery in TCCs Consolidated Statements of Income. Of the $302 million recorded in 2004, approximately $109 million,

$105 million and $88 million related to the years 2004, 2003 and 2002, respectively. The remaining equity component of $168 million will be recognized in income as collected. TCC will continue to accrue a carrying cost at the rate set forth above until it recovers its approved net true-up regulatory asset. If the PUCT further adjusts TCCs net true-up regulatory asset in TCCs True-up Proceeding, the carrying cost will also be adjusted.

When the True-up Proceeding is completed, TCC intends to file to recover PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through nonbypassable transition charges and competition transition charges in the regulated T&D rates. TCC will seek to securitize the approved net stranded generation costs plus related carrying costs. The securitizable portion of this net true-up regulatory asset, which consists of net stranded generation costs plus related carrying costs, was $1.4 billion at December 31, 2004. The other approved net true-up items will be recovered or refunded over time through a nonbypassable competition transition wires charge or credit inclusive of a carrying cost. We expect that TCCs True-up Proceeding filing will seek to recover an amount in excess of the total of its recorded net true-up regulatory asset through December 31, 2004. The PUCT will review TCCs filing and determine the amount for the recoverable net true-up regulatory assets.

Due to differences between CenterPoints and TCCs facts and circumstances, the lack of direct applicability of certain portions of the CenterPoint Order to TCC and the unknown nature of future developments in TCCs True-up Proceeding, we cannot, at this time, determine if TCC will incur additional disallowances in its True-up Proceeding. We believe that TCCs recorded net true-up regulatory asset at December 31, 2004 is in compliance with the Texas Restructuring Legislation, and the applicable portions of the CenterPoint Order and other nonaffiliated true-up orders, and we intend to seek vigorously its recovery. If, however, TCC determines that it is probable it cannot recover a portion of its recorded net true-up regulatory asset of $1.6 billion at December 31, 2004 and TCC is able to estimate the amount of such nonrecovery, TCC will record a provision for such amount, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition. To the extent decisions in the TCC True-up Proceeding differ from managements interpretation of the Texas Restructuring Legislation and its evaluation of the applicable portions of the CenterPoint and other true-up orders, additional material disallowances are possible.

See TEXAS RESTRUCTURING section of Note 6 for further discussion of Texas Regulatory Activity.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCCs proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%.

In February 2004, eight intervening parties and the PUCT Staff filed testimony recommending reductions to TCCs requested $67 million annual rate increase. Their recommendations ranged from a decrease in annual existing rates of approximately $100 million to an increase in TCCs current rates of approximately $27 million. Hearings were held in March 2004. In May 2004, TCC agreed to a nonunanimous settlement on cost of capital including capital structure and return on equity with all but two parties in the proceeding. TCC agreed that the return on equity should be established at 10.125% based upon a capital structure with 40% equity resulting in a weighted cost of capital of 7.475%. The settlement and other agreed adjustments reduced TCCs rate request from an increase of $67 million to an increase of $41 million.

On July 1, 2004, the ALJs who heard the case issued their recommendations, which included a recommendation to approve the cost of capital settlement. The ALJs recommended that an issue related to the allocation of consolidated tax savings to the transmission and distribution utility be remanded back to the ALJs for additional evidence. On July 15, 2004, the PUCT remanded this issue to the ALJs. On August 19, 2004, in a separate ruling, the PUCT remanded six other issues to the ALJs requesting revisions to clarify and support the recommendations in the Proposal for Decision (PFD).

The PUCT ordered TCC to calculate its revenue requirements based upon the recommendations of the ALJs. On July 21, 2004, TCC filed its revenue requirements based upon the recommendations of the ALJs. According to TCCs calculations, the ALJs recommendations would reduce TCCs annual existing rates between $33 million and $43 million depending on the final resolution of the amount of consolidated tax savings.

On November 16, 2004, the ALJs issued their PFD on remand, increasing their recommended annual rate reduction to a range of $51 million to $78 million, depending on the amount disallowed related to affiliated AEPSC billed expenses. At the January 13, 2005 and January 27, 2005 open meetings, the Commissioners considered a number of issues, but deferred resolution of the affiliated AEPSC billed expenses issue, among other less significant issues, until after additional hearings scheduled for early March 2005. Adjusted for the decisions announced by the Commissioners in January 2005, the ALJs disallowance would yield an annual rate reduction of a range of $48 million to $75 million. If TCC were to prevail on the affiliated expenses issue and all remaining issues, the result would be annual rate increase of $6 million. When issued, the PUCT order will affect revenues prospectively. An order reducing TCCs rates could have a material adverse effect on future results of operations and cash flows.

Ohio Regulatory Activity - Affecting CSPCo and OPCo

The Ohio Electric Restructuring Act of 1999 (Ohio Act) provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. On February 9, 2004, CSPCo and OPCo filed rate stabilization plans with the PUCO addressing prices for the three-year period following the end of the MDP, January 1, 2006 through December 31, 2008. The plans are intended to provide price stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEPs generation resources that serve Ohio customers. On January 26, 2005, the PUCO approved the plans with some modifications.

The approved plans include annual, fixed increases in the generation component of all customers bills (3% a year for CSPCo and 7% a year for OPCo) in 2006, 2007 and 2008. The plan also includes the opportunity to annually request an additional increase in supply prices averaging up to 4% per year for each company to recover certain new governmentally mandated increased expenditures set out in the approved plan. The plans maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level in effect on December 31, 2005. Such rates could be adjusted with PUCO approval for specified reasons. Transmission charges could also be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion and ancillary services. The approved plans provide for the continued amortization and recovery of stranded transition generation-related regulatory assets. The plans, as modified by the PUCO, require CSPCo and OPCo to allot a combined total of $14 million of previously provided unspent shopping incentives for the benefit of their low-income customers and economic development over the three-year period ending December 31, 2008 which will not have an effect on net income. The plans also authorized each company to establish unavoidable riders applicable to all distribution customers in order to be compensated in 2006 through 2008 for certain new costs incurred in 2004 and 2005 of fulfilling the companies Provider of Last Resort (POLR) obligations. These costs include RTO administrative fees and congestion costs net of financial transmission revenues and carrying cost of environmental capital expenditures. As a result,in 2005, CSPCo and OPCoexpect to record regulatory assets of approximately $8 million and $21 million, respectively,for the subject costsrelated to2004 and $14 million and $52 million, respectively, for expected subject costs related to 2005. These regulatory assets totaling $22 million for CSPCo and $73 million for OPCo will be amortized as the costs are recovered through POLR riders in 2006 through 2008. The riders, together with the fixed annual increases in generation rates are estimated to provide additional cumulative revenues to CSPCo and OPCo of $190 million and $500 million, respectively, in the three-year period ended December 31, 2008. Other revenue increases may occur related to other provisions of the plans discussed above.

On February 25, 2005, various intervenors filed Applications for Rehearing with the PUCO regarding their approval of the rate stabilization plans.Management expects the PUCO to address the applications before the end of March 2005. Management cannot predict the ultimate impact these proceedings will have on the results of operations and cash flows.

See OHIO RESTRUCTURING section of Note 6 for further discussion of Ohio Regulatory Activity.

Oklahoma Regulatory Activity - Affecting PSO

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West electric operating companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSOs 2001 fuel and purchased power practices. PSO filed testimony in February 2004.

An intervenor and the OCC Staff filed testimony in April 2004. The intervenor suggested that $9 million related to the 2002 reallocation not be recovered from customers. The Attorney General of Oklahoma also filed a statement of position, indicating allocated off-system sales margins between and among AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and, if corrected, could more than offset the $44 million 2002 reallocation under-recovery. The intervenor and the OCC Staff also argued that off-system sales margins were allocated incorrectly. The intervenors reallocation of such margins would reduce PSOs recoverable fuel costs by $7 million for 2000 and $11 million for 2001, while under the OCC Staff method, the reduction for 2001 would be $9 million. The intervenor and the OCC Staff also recommended recalculation of PSOs fuel costs for years subsequent to 2001 using the same revised methods. At a June 2004 prehearing conference, PSO questioned whether the issues in dispute were under the jurisdiction of the OCC because they relate to FERC-approved allocation agreements. As a result, the ALJ ordered that the parties brief the jurisdictional issue. PSO filed its brief on September 1, 2004. After reviewing the briefs, the ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. In January 2005, the OCC conducted a hearing on the jurisdictional matter and a ruling is expected in the near future. Management is unable to predict the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

PSO Rate Review

In February 2003, the OCC Staff filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003 and June 2004, PSO filed financial information and supporting testimony in response to the OCC Staffs request. PSOs initial response indicated that its annual revenues were $36 million less than costs. The June 2004 filing updated PSOs request and indicated a $41 million revenue deficiency. As a result, PSO sought OCC approval to increase its base rates by that amount, which is a 3.9% increase over PSOs existing revenues.

In August 2004, PSO filed a motion to amend the timeline to consider new service quality and reliability requirements, which took effect on July 1, 2004. Also in August 2004, the OCC approved a revised schedule. In October 2004, PSO filed supplemental information requesting consideration of approximately $55 million of additional annual operations and maintenance expenses and annual capital costs to enhance system reliability. In November 2004, PSO filed a plan with the OCC seeking interim rate relief to fund a portion of the costs to meet the new state service quality and reliability requirements pending the outcome of the current case. In the filing, PSO sought interim approval to collect annual incremental distribution tree trimming costs of approximately $23 million from its customers. Intervenors and the OCC Staff filed testimony recommending that the interim rate relief requested by PSO be modified or denied. The OCC issued an order on PSOs interim request in January 2005, which allows PSO to recover up to an additional $12 million annually for reliability activities beginning in December 2004. Expenses exceeding that amount and the amount currently included in base rates will be considered in the base rate case.

The OCC Staff and intervenors filed testimony regarding their recommendations on revenue requirement, fuel procurement, resource planning and vegetation management in January 2005. Their recommendations ranged from a decrease in annual existing rates between $15 million and $36 million. In addition, one party recommended that the OCC require PSO file additional information regarding its natural gas purchasing practices. In the absence of such a filing, this party suggested that $30 million of PSOs natural gas costs not be recovered from customers because it failed to implement a procurement strategy that, according to this party, would have resulted in lower natural gas costs. OCC Staff and intervenors recommended a return on common equity ranging from 9.3% to 10.11%. PSOs rebuttal testimony was filed in February 2005, and that testimony reflects a number of adjustments to PSOs June 2004 updated filing. These adjustments result in a decrease of PSOs revenue deficiency from $41 million to $28 million, although approximately $9 million of that decrease are items that would be recovered through the fuel adjustment clause rather than through base rates. Hearings are scheduled to begin in March 2005, and a final decision is not expected any earlier than the second quarter of 2005. Management is unable to predict the ultimate effect of these proceedings on PSOs revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates - Affecting AEP East Companies

In July 2003, the FERC issued an order directing PJM and the Midwest Independent System Operator (MISO) to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and expanded PJM regions (Combined Footprint). The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners including AEP East companies under the RTOs revenue distribution protocols.

In November 2003, the FERC issued an order finding that the T&O rates of the former Alliance RTO participants, including AEP, should also be eliminated for transactions within the Combined Footprint. The order directed the RTOs and former Alliance RTO participants to file compliance rates to eliminate T&O rates prospectively within the Combined Footprint and simultaneously implement a load-based transitional rate mechanism called the seams elimination cost allocation (SECA), to mitigate the lost T&O revenues for a two-year transition period beginning April 1, 2004. The FERC was expected to implement a new rate design after the two-year period. In April 2004, the FERC approved a settlement that delayed elimination of T&O rates and the implementation of SECA replacement rates until December 1, 2004 when the FERC would implement a new rate design.

On November 18, 2004, the FERC conditionally approved a license plate rate design to eliminate rate pancaking for transmission service within the Combined Footprint and adopted its previously approved SECA transition rate methodology to mitigate the effects of the elimination of T&O rates effective December 1, 2004. Under license plate rates, customers serving load within a RTO pay transmission service rates based on the embedded cost of the transmission facilities in the local pricing zone where the load being served is located. The use of license plate rates would shift costs that were previously recovered from T&O service customers to mainly AEPs native load customers within the AEP East pricing zone. The SECA transition rates will remain in effect through March 31, 2006. The SECA rates are designed to mitigate the loss of revenues due to the elimination of T&O rates.

The SECA rates became effective December 1, 2004. Billing statements from PJM for December 2004 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP East companies accrued $11 million in December 2004 for SECA revenues. On January 7, 2005, AEP and Exelon filed joint comments and protest with the FERC including a request that FERC direct PJM and MISO to comply with the FERC decision and collect all SECA revenues due with interest charges for all late-billed amounts. On February 10, 2005, the FERC issued an orderindicating that the SECA transition rates would be subject to refund or surcharge andset for hearing all remaining aspects of the compliance filings to the November 18 order, including AEP's request that the FERC direct PJM and MISO begin billing and collecting the SECA transition rates.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA charges was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEPs internal load will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate the AEP East companies for its lost T&O revenues through March 31, 2006, or if any increase in the AEP East Companies transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Pension and Postretirement Benefit Plans

AEP maintains qualified, defined benefit pension plans (Qualified Plans or Pensions Plans), which cover a substantial majority of nonunion and certain union associates, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, AEP has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits. AEP also sponsors other postretirement benefit plans to provide medical and life insurance benefits for retired employees in the U.S. (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively the Plans.

The following table shows the net periodic cost (credit) for AEPs Pension Plans and Postretirement Plans:

	2004	2003
	(in millions)	
Net Periodic Cost (Credit):		
Pension Plans	$ 40	$ (3)
Postretirement Plans	141	188
Assumed Rate of Return:		
Pension Plans	8.75 %	9.00 %
Postretirement Plans	8.35 %	8.75 %

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans assets. In developing the expected long-term rate of return assumption, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. AEP also considered historical returns of the investment markets as well as its 10-year average return, for the period ended December 2004, of approximately 12%. AEP anticipates that the investment managers employed for the Plans will continue to generate long-term returns averaging 8.75%.

The expected long-term rate of return on the Plans assets is based on AEPs targeted asset allocation and its expected investment returns for each investment category. AEPs assumptions are summarized in the following table:

	2004 Actual Pension **Plan Asset Allocation**	**2004 Actual Postretirement Plan Asset Allocation**	**2005 Target Asset Allocation**	**Assumed/Expected Long-term Rate of Return**
Equity	68 %	70 %	70 %	10.50 %
Fixed Income	25 %	28 %	28 %	5.00 %
Cash and Cash Equivalents	7 %	2 %	2 %	2.00 %
Total	100 %	100 %	100 %	
Overall Expected Return(weighted average)				8.75 %

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. Because of a $200 million discretionary contribution to the Qualified Plans at the end of 2004, the actual asset allocation was different from the target allocation at the end of the year. The asset portfolio was rebalanced back to the target allocation in January 2005. AEP believes that 8.75% is a reasonable long-term rate of return on the Plans assets despite the recent market volatility. The Plans assets had an actual gain of 13.75% and 23.80% for the twelve months ended December 31, 2004 and 2003, respectively. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2004, AEP had cumulative losses of approximately $30 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, Employers Accounting for Pensions.

The method used to determine the discount rate that AEP utilizes for determining future obligations was revised in 2004. Historically, AEP based it on the Moodys AA bond index which includes long-term bonds that receive one of the two highest ratings from a recognized rating agency. The discount rate determined on this basis was 6.25% at December 31, 2003 and would have been 5.75% at December 31, 2004. In 2004, AEP changed to a duration based method where a hypothetical portfolio of high quality corporate bonds was constructed with a duration similar to the duration of the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2004 under this method was 5.50% for the Pension Plans and 5.80% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Plans assets of 8.75%, a discount rate of 5.50% and various other assumptions, AEP estimates that the pension cost for all pension plans will approximate $55 million, $54 million and $61 million in 2005, 2006 and 2007, respectively. AEP estimates Postretirement Plan cost will approximate $164 million, $155 million and $146 million in 2005, 2006 and 2007, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 0.5% basis point change to selective actuarial assumptions are in Pension and Other Postretirement Benefits within the Critical Accounting Estimates section of this Combined Managements Discussion and Analysis of Registrant Subsidiaries.

The value of AEPs Pension Plans assets increased to $3.6 billion at December 31, 2004 from $3.2 billion at December 31, 2003. The Qualified Plans paid $265 million in benefits to plan participants during 2004 (nonqualified plans paid $8 million in benefits). The value of AEPs Postretirement Plans assets increased to $1.1 billion at December 31, 2004 from $1.0 billion at December 31, 2003. The Postretirement Plans paid $109 million in benefits to plan participants during 2004.

For AEPs underfunded pension plans, the accumulated benefit obligation in excess of plan assets was $474 million and $445 million at December 31, 2004 and 2003, respectively.

A minimum pension liability is recorded for pension plans with an accumulated benefit obligation in excess of the fair value of plan assets. The minimum pension liability for the underfunded pension plans declined during 2004 and 2003, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2004	**2003**
	(in millions)	
Other Comprehensive Income	$ (92)	$ (154)
Deferred Income Taxes	(52)	(75)
Intangible Asset	(3)	(5)
Other	(10)	13
Minimum Pension Liability	$ (157)	$ (221)

AEP made an additional discretionary contribution of $200 million in the fourth quarter of 2004 and intends to make additional discretionary contributions of $100 million per quarter in 2005 to meet the goal of fully funding all Qualified Plans by the end of 2005.

Certain pension plans AEP sponsors and maintains contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. AEP believes that the defined benefit pension plans it sponsors and maintains are in compliance with the applicable requirements of such laws.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under Environmental Matters.

Enron Bankruptcy

In 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enrons bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enrons bankruptcy.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEPs offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. AEP asserted its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. The parties are currently in nonbinding, court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enrons claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

The amounts expensed in prior years in connection with the Enron bankruptcy were based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and managements analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on results of operations, cash flows and financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be physically interconnected and confined to a single area or region. In January 2005, a hearing was held before an ALJ. Management expects an initial decision from the ALJ later this year. The SEC will review the initial decision.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against AEP and four of its subsidiaries including TCC and TNC, certain nonaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial courts decision to the United States Court of Appeals for the Fifth Circuit.

Coal Transportation Dispute

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, have disputed transportation costs billed for coal received between July 2000 and the present time. The joint plant has remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded a provision for possible loss in December 2004 and a receivable from the other owners. The provision was deferred as a regulatory asset under PSOs fuel mechanism and affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Other Litigation

AEP subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on results of operations, cash flows or financial condition.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that management expects will result in substantial capital investments and operational costs. The sources of these future requirements include:

Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,

New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
Possible future requirements to reduce carbon dioxide emissions to address concerns about global climate change.

In addition to achieving full compliance with all applicable legal requirements, AEP subsidiaries strive to go beyond compliance in an effort to be good environmental stewards. For example, AEP subsidiaries invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. AEP subsidiaries plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. AEP subsidiaries have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. The AEP System has invested over $2 billion, from 1990 through 2004, to equip many of its facilities with pollution control technologies. The AEP System will continue to make investments to improve the air emissions from its fossil fuel generating stations as this is the most cost-effective generation source to meet its customers electricity needs.

In 2002, the AEP System joined the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program. AEP subsidiaries committed to reduce or offset approximately 18 million short tons of CO_2 emissions during 2003-2006 below baseline emissions (i.e. average emission levels during 1998-2001) as adjusted to reflect any changes in the baseline during the commitment period. During 2003, AEP subsidiaries reduced or offset emissions by approximately seven million tons below the voluntary emissions cap and, based on preliminary estimates, AEP subsidiaries anticipate being below the voluntary emissions cap in 2004.

In August 2004, management released An Assessment of AEPs Actions to Mitigate the Economic Impacts of Emissions Policies. The assessment evaluated the AEP Systems operating emissions control technology, planned investment in additional control equipment and risks associated with an uncertain regulatory environment. It concluded that AEPs actions over the past decade constitute a solid foundation for future efforts to address the intersection between environmental policy and business opportunities. It also concluded that irrespective of the uncertainties surrounding potential air emission regulations and possible future mandatory greenhouse gas regulations, the pollution control investments planned over the next six to eight years are sound. The report also details many of the voluntary actions to be undertaken to limit greenhouse gas emissions and to develop and/or advance future clean energy technologies.

The Current Air Quality Regulatory Framework

The CAA establishes the federal regulatory authority and oversight for emissions from fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as national ambient air quality standards (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing nonattainment areas into compliance with the NAAQS. In developing a SIP, each state must demonstrate that attainment areas will maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring nonattainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each states SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to nonattainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NO_x Rule in 1997, which affected 22 eastern states (including states in which AEP subsidiaries operate) and the District of Columbia. The NO_x Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NO_x emissions. The purpose of the request was to reduce the contribution from these 23 jurisdictions to ozone nonattainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which the AEP System operates that were subject to the NO_x Rule have submitted the required SIP revisions. In response, the Federal EPA approved the SIPs. The compliance date for the

SIPs implementing the NO_x Rule and the revised Section 126 Rule was May 31, 2004. The requirements apply to most of the AEP Systems coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality (TCEQ) adopted rules requiring significant reductions in NO_x emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and will begin in May 2005 for SWEPCo.

AEP subsidiaries installed a variety of emission control technologies to reduce NO_x emissions and to comply with applicable state and federal NO_x requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEPs electric generating units are currently subject to other SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NO_x emissions in certain states. Management believes that the AEP Systems generating plants comply with applicable SIP limits for SO_2, NO_x and particulate matter.

Hazardous Air Pollutants: In the 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPAs 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric generating units are regulated under the NSPS for SO_2, NO_x, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and nonattainment areas.

In attainment areas:

An air quality review must be performed, and

The best available control technology must be employed to reduce new emissions.

In nonattainment areas:

Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and

All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric generating units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers the SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each generating unit surrenders one allowance for each ton of SO_2 that it emits. Emission sources may bank their excess allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NO_x emissions through the use of available combustion controls. Generating units must meet their specific NO_x emission standards or units under common control may participate in an annual averaging program for that group of units.

Future Reduction Requirements for SO_2, NO_x and Mercury

In 1997, the Federal EPA adopted more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA finalized designations for fine particulate matter nonattainment areas on December 17, 2004. Approximately 200 counties are included in the nonattainment areas including many rural counties in the Eastern United States where our generating units are located. The Federal EPA has not yet issued a rule establishing planning and control requirements or attainment deadlines for these areas. The Federal EPA finalized designations for ozone nonattainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final rule establishing the elements that must be included in SIPs to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of nonattainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA has identified SO_2 and NO_x emissions as precursors to the formation of fine particulate matter. NO_x emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NO_x and SO_2 from the AEP Systems generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation is supported by the Bush Administration. This legislation would regulate NO_x, SO_2, and mercury emissions from electric generating plants. AEP supports enactment of a comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Management believes this legislation would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Management believes regulation or legislation will require the AEP System to substantially reduce SO_2, NO_x and mercury emissions over the next ten years.

Regulatory Emissions Reductions

In January 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the eastern half of the United States (29 states and the District of Columbia) and make progress toward attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The CAIR would require affected states to include, in their SIPs, a program to reduce NO_x and SO_2 emissions from coal-fired electric utility units. SO_2 and NO_x emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NO_x emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NO_x trading programs were proposed in June 2004.

On April 15, 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include Best Available Retrofit requirements for individual facilities in their SIPs to address regional haze. The guidance applies to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The Federal EPA included an alternative Best Available Retrofit program based on emissions budgeting and trading programs. For generating units that are affected by the CAIR, described above, the Federal EPA proposed that participation in the trading program under the CAIR would satisfy any applicable Best Available Retrofit requirements. However, the guidance preserves the ability of a state to require site-specific installation of pollution control equipment through the SIP for purposes of abating regional haze.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain generating units have achieved comparable levels of mercury reduction by installing conventional SO_2 (scrubbers) and NO_x (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite. The proposed standards for sub-bituminous coals potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NO_x reduction requirements imposed on the same sources under the CAIR. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs which can be used to comply with the more stringent SO_2 and NO_x requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register in March 2004. We filed comments on both the initial proposal and the supplemental proposal in June 2004.

The Federal EPAs proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their coal-fired power plants. Finalization of new requirements for further SO_2, NO_x and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control. The cost of such facilities could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and may be the subject of a court challenge and further modifications.

All of managements estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:

Timing of implementation

Required levels of reductions
Allocation requirements of the new rules, and
Selected compliance alternatives.

As a result, management cannot estimate compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to the AEP subsidiaries current investment base and operating cost structure. Management intends to seek recovery of these expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions). Management believes market prices should allow recovery of these expenditures in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NO_x Compliance

Management estimates that AEP subsidiaries will make future investments of approximately $450 million to comply with the Federal EPAs NO_x Rule, the TCEQ Rule and other final NO_x-related requirements. Approximately $380 million of these investments are expected to be expended during 2005-2007. As of December 31, 2004, the AEP System has invested approximately $1.3 billion to comply with various NO_x requirements. Estimated future compliance costs, investment amounts estimated for 2005-2007 and amounts spent by subsidiaries are as follows:

	Future Estimated Compliance Investment	Investment Amount Estimated for 2005 - 2007	Amount Spent
		(in millions)	
AEGCo	$ -	$ -	$ 17
APCo	47	42	425
CSPCo	24	7	87
I&M	-	-	22
KPCo	48	-	181
OPCo	319	319	496
SWEPCo	14	11	25

Estimated Investments for SO_2 Compliance

The AEP System is complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. AEP subsidiaries also use SO_2 allowances that were:

Received in the Federal EPAs annual allowance allocation,

Obtained through participation in the annual Federal allowance auction,

Purchased in the market, and
Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require the installation of additional controls on certain generating units. AEP subsidiaries plan to install 3,500 MW of additional scrubbers to comply with our Title IV SO_2 obligations. In total, management estimates these additional capital costs to be approximately $1.2 billion with approximately $97 million invested during 2004 and the remainder will be expended during 2005-2007. The following table shows the estimated additional capital costs and amounts for 2005-2007 for additional scrubbers by subsidiary:

	Cost of Additional Scrubbers	Amount Estimated for 2005 - 2007
	(in millions)	
APCo	$ 442	$ 442
OPCo	727	714
SWEPCo	19	19

Estimated Investments to Comply with Future Reduction Requirements

The AEP Systems planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. Management has also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NO_x and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. Management estimates that the subsidiaries will invest $1 billion of this amount through 2007.

	Estimated Compliance Investments	Amount Estimated for 2005 - 2007
	(in millions)	
APCo	$ 628	$ 469
CSPCo	236	133
I&M	61	8
KPCo	383	49
OPCo	364	319
SWEPCo	54	18

Management also estimates that the subsidiaries would incur increases in variable operation and maintenance expenses of $150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents.

If the Federal EPAs preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would have higher implementation costs that could be significant. Management cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that the AEP System operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which management is not able to estimate, would be incremental to other cost estimates that are discussed above.

Between 2010 and 2020, the AEP System expects to incur additional costs for pollution control technology retrofits and investment of

$1.6 billion. However, the post-2010 capital investment estimates are quite uncertain, reflecting the uncertain nature of future air emission regulatory requirements, technology performance and costs, new pollution control and generating technology developments, among other factors. Associated operation and maintenance expenses for the equipment will also increase during those years. Management cannot estimate these additional costs because of the uncertainties associated with the final control requirements and the associated compliance strategy, but these additional costs are expected to be significant.

New Source Review Litigation

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at the generating units over a 20-year period.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to perfect its complaint in the pending litigation. The NOV expands the number of alleged modifications undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, eight Northeastern States filed a separate complaint containing the same allegations against the Conesville and Amos plants that the judge disallowed in the pending case. AEP subsidiaries filed an answer to the complaint in January 2005.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If the AEP subsidiaries do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered from customers.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio SIP occurred at the Stuart Station, and seeking injunctive relief and civil penalties. Stuart Station is jointly-owned by CSPCo (26%) and two nonaffiliated utilities. The owners have filed a motion to dismiss portions of the complaint. The owners believe the allegations in the complaint are without merit, and intend to defend vigorously against this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. This notice was prompted by allegations made by a terminated AEP employee. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions.

On July 19, 2004, the TCEQ issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On August 30, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the reporting of volatile organic compound emissions at the Pirkey Plant, but after investigation determined that further enforcement was not warranted and withdrew the notice on January 5, 2005.

SWEPCo has previously reported to the TCEQ, deviations related to the receipt of off-specification fuel at Knox Lee, the volatile organic compound emissions at Pirkey, and the referenced recordkeeping and reporting requirements and heat input value at Welsh. We have submitted additional responses to the Notice of Enforcement and the notice from the special interest groups. Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generation plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and nonhazardous materials. AEP subsidiaries are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2004, APCo, CSPCo, I&M and OPCo are each named by the Federal EPA as a Potentially Responsible Party (PRP) for one site. There are six additional sites for which APCo, CSPCo, I&M, KPCo, OPCo and SWEPCo have received information requests which could lead to PRP designation. OPCo, SWEPCo and TCC have also been named potentially liable at four sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where AEP subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, present estimates do not anticipate material cleanup costs for identified sites for which AEP subsidiaries have been declared PRPs. If significant cleanup costs are attributed to any AEP subsidiary in the future under Superfund, its results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in its electricity prices.

Emergency Release Reporting

Superfund also requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances which cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. The Federal EPA's Complaint seeks an immaterial amount of civil penalties. I&M has requested a hearing and raised several defenses to the claim, including federally permitted release exemption from reporting. Negotiations on the penalty amount are continuing.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCos Gavin Plant SCR system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries legislative bodies is required for it to be enforceable. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries and is now in effect as of February 2005.

In August 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the CAA to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

AEP has been working with the Bush Administration on a voluntary program aimed at meeting the Presidents goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, AEP has been a leader in pursuing voluntary actions to control greenhouse gas emissions. AEP expanded its commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program. AEP subsidiaries made a voluntary commitment to reduce or offset 18 million tons of CO_2 emissions during 2003-2006 as adjusted to reflect any changes in baseline during the commitment period.

Carbon Dioxide Public Nuisance Claims

On July 21, 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions allege that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and seek injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. Management believes the actions are without merit and intends to defend vigorously against the claims.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOEs SNF disposal program which is described in the SNF Disposal section of Note 7. Since 1983, I&M has collected $333 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. I&M deposited $118 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $215 million to the DOE. TCC has collected and remitted to the DOE, $61 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, the DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other nonaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOEs complete failure to perform its contract obligations, and that the utilities suits against DOE may continue in court. In January 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continued on the issue of damages owed to I&M by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against I&M and denied damages. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. As long as the delay in the availability of a government-approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2004, the total decommissioning trust fund balance for Cook Plant was $791 million, which includes earnings on the trust investments. In May 2004, an updated decommissioning study was completed for STP. The study estimates TCCs share of the decommissioning costs of STP to be $344 million in nondiscounted 2004 dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2004, the total decommissioning trust fund for TCCs share of STP was $143 million, which includes earnings on the trust investments. TCC is in the process of selling its ownership interest in STP to two nonaffiliated companies, and upon completion of the sale it is anticipated that TCC will no longer be obligated for nuclear decommissioning liabilities associated with STP. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On July 9, 2004, the Federal EPA published in the Federal Register a rule pursuant to the Clean Water Act that will require all large existing, once-through cooled power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plants cooling water intake screen. All plants must reduce fish mortality by 80% to 95%. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. These plants must reduce the rate of smaller organisms passing through the plant by 60% to 90%. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large generating plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance. The estimated capital cost of compliance for AEP System facilities, based on the Federal EPAs analysis in the rule, is $193 million. Any capital costs associated with compliance activities to meet the new performance standards would likely be incurred during the years 2008 through 2010. Management has not independently confirmed the accuracy of the Federal EPAs estimate. The rule has provisions to limit compliance costs. Management may propose less costly site-specific performance criteria if compliance cost estimates are significantly greater than the Federal EPAs estimates or greater than the environmental benefits. The rule also allows Management to propose mitigation (also called restoration measures) that is less costly and has equivalent or superior environmental benefits than meeting the criteria in whole or in part. Several states, electric utilities (including APCo) and environmental groups appealed certain aspects of the rule. We cannot predict the outcome of the appeals. The following table shows the investment amount per subsidiary.

Estimated Compliance Investments

		(in millions)
APCo	$	21
CSPCo		19
I&M		118

Other Environmental Concerns

Management performs environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, the AEP subsidiaries are managing other environmental concerns which are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

it requires assumptions to be made that were uncertain at the time the estimate was made; and

changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated results of operations or financial condition.

Management has discussed the development and selection of its critical accounting estimates as presented below with the Audit Committee of AEPs Board of Directors and the Audit Committee has reviewed the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

The sections that follow present information about the Registrant Subsidiaries most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required - The consolidated financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (I&M, KPCo, PSO and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo) reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recognized for the economic effects of regulation by matching the timing of expense recognition with the recovery of such expense in regulated revenues. Likewise, income is matched with the passage to customers through regulated revenues in the same accounting period.

Regulatory liabilities are also recorded for refunds, or probable refunds, to customers that have not yet been made.

Assumptions and Approach Used - When regulatory assets are probable of recovery through regulated rates, they are recorded as assets on the balance sheet. Regulatory assets are tested for probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If it is determined that recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used - A change in the above assumptions may result in a material impact on the results of operations. Refer to Note 5 of the Notes to Financial Statements of Registrant Subsidiaries for further detail related to regulatory assets and liabilities.

Revenue Recognition - Unbilled Revenues

Nature of Estimates Required - Revenues are recognized and recorded when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is also estimated. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

Unbilled revenues included in Revenue for the years ended December 31 were as follows:

	2004	2003	2002
		(in thousands)	
TCC	$ (1,579)	$ 4,636	$ (19,023)
TNC	(1,160)	1,834	(1,775)
APCo	18,206	1,876	3,890
CSPCo	283	(5,881)	6,917
I&M	(2,942)	10,722	9,329
KPCo	3,833	(448)	708
OPCo	(2,793)	(18,502)	(346)
PSO	2,789	984	4,008
SWEPCo	1,814	(6,996)	3,637

Assumptions and Approach Used - The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current months billed KWH plus the prior months unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation determines factors that limit the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are then statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

In addition, an annual comparison to a load research estimate is performed for the East Companies. The annual load research study is an independent unbilled KWH estimate based on a sample of accounts. The unbilled estimate is also adjusted annually for significant differences from the load research estimate.

Effect if Different Assumptions Used - Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1%.

Revenue Recognition - Accounting for Derivative Instruments

Nature of Estimates Required - Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used - APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates based upon the best market information available is somewhat subjective in nature and involves uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided for in the original documentation related to hedge accounting.

Effect if Different Assumptions Used - There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified in operating income.

Long-Lived Assets

Nature of Estimates Required - In accordance with the requirements of SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. These events or circumstances may include the expected ability to recover additional investment in environmental compliance expenditures, the relative pricing of wholesale electricity by region, the anticipated demand and the cost of fuel. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For nonregulated assets, an impairment charge would be recorded as a charge against earnings.

Assumptions and Approach Use - The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales, or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used - In connection with the periodic evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. In cases of impairment as described in Note 10, the best estimate of fair value was made using valuation methods based on the most current information at that time. Certain Registrant Subsidiaries have been in the process of divesting certain noncore assets and their sales values can vary from the recorded fair value as described in Note 10. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and managements analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required - APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under SFAS 87, Employers Accounting For Pensions and SFAS 106, Employers Accounting for Postretirement Benefits Other Than Pensions, respectively. See Note 11 of the Notes to Financial Statements of Registrant Subsidiaries for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by actuaries and APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded.

Assumptions and Approach Used - The critical assumptions used in developing the required estimates include the following key factors:

- discount rate
- expected return on plan assets
- health care cost trend rates
- rate of compensation increases

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used - The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		**Other Postretirement Benefits Plans**	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
			(in millions)	
Effect on December 31, 2004 BenefitObligations:				
Discount Rate	$ (175)	$ 182	$ (133)	$ 142
Salary Scale	11	(11)	4	(4)
Cash Balance Crediting Rate	(20)	20	N/A	N/A
Health Care Trend Rate	N/A	N/A	129	(121)
Expected Return on Assets	N/A	N/A	N/A	N/A
Effect on 2004 Periodic Cost:				
Discount Rate	-	1	(11)	11
Salary Scale	2	(2)	1	(1)
Cash Balance Crediting Rate	3	(3)	N/A	N/A
Health Care Trend Rate	N/A	N/A	19	(18)

Expected Return on Assets	(17)	17	(5)	5

New Accounting Pronouncements

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC implemented FASB Staff Position (FSP) FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, effective April 1, 2004, retroactive to January 1, 2004. Under FSP FAS 106-2, the current portion of the Medicare subsidy for employers who qualify for the tax-free subsidy is a reduction of ongoing FAS 106 cost, while the retroactive portion is an actuarial gain to be amortized over the average remaining service period of active employees, to the extent that the gain exceeds FAS 106s 10 percent corridor.

In December 2004, the FASB issued SFAS 123R, Share-Based Payment. SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. We will implement SFAS 123R in the third quarter of 2005 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

We implemented FIN 46R, Consolidated of Variable Interest Entities, effective March 31, 2004 with no material impact to our financial statements. FIN 46R is a revision to FIN 46 which interprets the application of Accounting Research Bulletin No. 51, Consolidated Financial Statements, to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties.

Other Matters

Seasonality

The sale of electric power in AEP subsidiaries service territories is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of the AEP Systems facilities and the terms of power contracts into which AEP enters. In addition, AEP subsidiaries have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish results of operations and may impact cash flows and financial condition.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-87216 of Kentucky Power Company on Form S-3 of our reports dated February 28, 2005 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2003 and 2004) relating to the financial statements and financial statement schedules of Kentucky Power Company appearing in and incorporated by reference in the Annual Report on Form 10-K of Kentucky Power Company for the year ended December 31, 2004.

/s/ Deloitte & Touche, LLP

Columbus, Ohio

March 1, 2005

Exhibit 24

POWER OF ATTORNEY

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2004

The undersigned directors of the following companies (each respectively the "Company"):

Company	**State of Incorporation**
Appalachian Power Company	Virginia
Columbus Southern Power Company	Ohio
Kentucky Power Company	Kentucky
Ohio Power Company	Ohio

do hereby constitute and appoint MICHAEL G. MORRIS, STEPHEN P. SMITH and SUSAN TOMASKY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2004, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 26 th day of January, 2005.

/s/ Carl L. English

/s/ Michael G. Morris

/s/ John B. Keane

/s/ Holly K. Koeppel

/s/ Venita McCellon-Allen

/s/ Robert P. Powers

/s/ Stephen P. Smith

/s/ Susan Tomasky

EXHIBIT 31.(a)

CERTIFICATION PURSUANT TO SECTION 302

OF THE SARBANES-OXLEY ACT OF 2002

I, Michael G. Morris, certify that:

1. I have reviewed this annual report on Form 10-K of:

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company;

2. Based on my knowledge, this 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 this report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 registrants other certifying officers 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)) for the registrant and we 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 report is being prepared;

Evaluated the effectiveness of the registrants 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 evaluations; and

Disclosed in this report any change in the registrants internal control over financial reporting that occurred during the registrants most recent fiscal quarter (the registrants fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrants internal control over financial reporting; and

5. The registrants other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting , to the registrants auditors and the audit committee of registrants board of directors (or persons performing the equivalent function):

All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrants ability to record, process, summarize and report financial information ; and

Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrants internal control over financial reporting .

Date: March 1, 2005 By: /s/ Michael G. Morris

Michael G. Morris

Chief Executive Officer

EXHIBIT 31.(b)

CERTIFICATION PURSUANT TO SECTION 302

OF THE SARBANES-OXLEY ACT OF 2002

I, Susan Tomasky, certify that:

1. I have reviewed this annual report on Form 10-K of:

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company;

2. Based on my knowledge, this 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 this report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 registrants other certifying officers 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)) for the registrant and we 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 report is being prepared;

b. Evaluated the effectiveness of the registrants 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 evaluations; and

d. Disclosed in this report any change in the registrants internal control over financial reporting that occurred during the registrants most recent fiscal quarter (the registrants fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrants internal control over financial reporting; and

5. The registrants other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting , to the registrants auditors and the audit committee of registrants board of directors (or persons performing the equivalent function):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrants 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 registrants internal control over financial reporting .

Date: March 1, 2005 By: /s/ Susan Tomasky

Susan Tomasky

Chief Financial Officer

Exhibit 32.(a)

This Certificate is being furnished and shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63

Of Title 18 of the United States Code

In connection with the Annual Report of the Companies (as defined below) on Form 10-K (the reports) for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof, I, Michael G. Morris, the chief executive officer of

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Michael G. Morris

Michael G. Morris

Chief Executive Officer

March 1, 2005

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.(b)

This Certificate is being furnished and shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63

Of Title 18 of the United States Code

In connection with the Annual Report of the Companies (as defined below) on Form 10-K (the reports) for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof, I, Susan Tomasky, the chief financial officer of

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Susan Tomasky

Susan Tomasky

Chief Financial Officer

March 1, 2005

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

End of Filing