INDIANA MICHIGAN POWER®
A unit of American Electric Power

Indiana Michigan Power
Cook Nuclear Plant
One Cook Place
Bridgman, MI 49106
AEP.com

May 30, 2006

AEP:NRC:6071-01
10 CFR 50.71(b)
10 CFR 140.21(e)

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, D.C. 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
2005 FINANCIAL INFORMATION FOR INDIANA MICHIGAN POWER COMPANY

In accordance with 10 CFR 50.71(b), Attachment 1 to this letter provides the Indiana Michigan Power Company (I&M) 2005 Annual Financial Report. Attachment 2 provides a copy of the year 2006 projected cash flow for I&M as required by 10 CFR 140.21(e).

This letter contains no new regulatory commitments. Should you have any questions, please contact Mr. Michael K. Scarpello, Regulatory Affairs Supervisor, at (269) 466-2649.

Sincerely,

Joseph N. Jensen
Site Vice President

DB/rdw

Attachments

c: J. L. Caldwell, NRC Region III
K. D. Curry, Ft. Wayne AEP, w/o attachments
J. T. King, MPSC, w/o attachments
MDEQ – WHMD/RPMWS
NRC Resident Inspector
P. S. Tam, NRC Washington, DC

M004

ATTACHMENT 1 TO AEP:NRC:6071-01

INDIANA MICHIGAN POWER COMPANY
2005 ANNUAL REPORT

Sections B through F and Sections H through K have been omitted from this attachment in order to provide only information relevant to the Licensee, Indiana Michigan Power Company.

2005 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
Management's Financial Discussion and Analysis

AEP

AMERICAN®
ELECTRIC
POWER

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO ANNUAL REPORTS

	Page
Glossary of Terms	i
Forward-Looking Information	iv
AEP Common Stock and Dividend Information	v
American Electric Power Company, Inc. and Subsidiary Companies:	
Selected Consolidated Financial Data	A-1
Management's Financial Discussion and Analysis of Results of Operations	A-2
Quantitative and Qualitative Disclosures About Risk Management Activities	A-32
Report of Independent Registered Public Accounting Firm	A-39
Management's Report on Internal Control Over Financial Reporting	A-41
Consolidated Financial Statements	A-42
Index to Notes to Consolidated Financial Statements	A-47
AEP Generating Company:	
Selected Financial Data	B-1
Management's Narrative Financial Discussion and Analysis	B-2
Financial Statements	B-4
Index to Notes to Financial Statements of Registrant Subsidiaries	B-8
Report of Independent Registered Public Accounting Firm	B-9
AEP Texas Central Company and Subsidiary:	
Selected Consolidated Financial Data	C-1
Management's Financial Discussion and Analysis	C-2
Quantitative and Qualitative Disclosures About Risk Management Activities	C-11
Consolidated Financial Statements	C-15
Index to Notes to Financial Statements of Registrant Subsidiaries	C-20
Report of Independent Registered Public Accounting Firm	C-21
AEP Texas North Company:	
Selected Financial Data	D-1
Management's Narrative Financial Discussion and Analysis	D-2
Quantitative and Qualitative Disclosures About Risk Management Activities	D-6
Financial Statements	D-9
Index to Notes to Financial Statements of Registrant Subsidiaries	D-14
Report of Independent Registered Public Accounting Firm	D-15
Appalachian Power Company and Subsidiaries:	
Selected Consolidated Financial Data	E-1
Management's Financial Discussion and Analysis	E-2
Quantitative and Qualitative Disclosures About Risk Management Activities	E-9
Consolidated Financial Statements	E-13
Index to Notes to Financial Statements of Registrant Subsidiaries	E-18
Report of Independent Registered Public Accounting Firm	E-19

Columbus Southern Power Company and Subsidiaries:

Selected Consolidated Financial Data	F-1
Management's Narrative Financial Discussion and Analysis	F-2
Quantitative and Qualitative Disclosures About Risk Management Activities	F-6
Consolidated Financial Statements	F-9
Index to Notes to Financial Statements of Registrant Subsidiaries	F-14
Report of Independent Registered Public Accounting Firm	F-15

Indiana Michigan Power Company and Subsidiaries:

Selected Consolidated Financial Data	G-1
Management's Financial Discussion and Analysis	G-2
Quantitative and Qualitative Disclosures About Risk Management Activities	G-9
Consolidated Financial Statements	G-13
Index to Notes to Financial Statements of Registrant Subsidiaries	G-18
Report of Independent Registered Public Accounting Firm	G-19

Kentucky Power Company:

Selected Financial Data	H-1
Management's Narrative Financial Discussion and Analysis	H-2
Quantitative and Qualitative Disclosures About Risk Management Activities	H-6
Financial Statements	H-9
Index to Notes to Financial Statements of Registrant Subsidiaries	H-14
Report of Independent Registered Public Accounting Firm	H-15

Ohio Power Company Consolidated:

Selected Consolidated Financial Data	I-1
Management's Financial Discussion and Analysis	I-2
Quantitative and Qualitative Disclosures About Risk Management Activities	I-9
Consolidated Financial Statements	I-13
Index to Notes to Financial Statements of Registrant Subsidiaries	I-18
Report of Independent Registered Public Accounting Firm	I-19

Public Service Company of Oklahoma:

Selected Financial Data	J-1
Management's Narrative Financial Discussion and Analysis	J-2
Quantitative and Qualitative Disclosures About Risk Management Activities	J-6
Financial Statements	J-9
Index to Notes to Financial Statements of Registrant Subsidiaries	J-14
Report of Independent Registered Public Accounting Firm	J-15

Southwestern Electric Power Company Consolidated:

Selected Consolidated Financial Data	K-1
Management's Financial Discussion and Analysis	K-2
Quantitative and Qualitative Disclosures About Risk Management Activities	K-10
Consolidated Financial Statements	K-13
Index to Notes to Financial Statements of Registrant Subsidiaries	K-18
Report of Independent Registered Public Accounting Firm	K-19

Notes to Financial Statements of Registrant Subsidiaries	L-1
Combined Management's Discussion and Analysis of Registrant Subsidiaries	M-1

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 AEP Resources, Inc.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or 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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
APB 25	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
Cook Plant	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.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
EITF	Financial Accounting Standards Board's 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.
EPACT	Energy Policy Act of 2005.
ERCOT	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."
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.

I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IPP	Independent Power Producers.
IURC	Indiana Utility Regulatory Commission.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
PURPA	Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
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 115	Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities."

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."
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
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 made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

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.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases.
- 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).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain operation and maintenance costs.
- Our ability to sell assets at acceptable prices and 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 and interest rate 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 of the counterparties with whom AEP has contractual arrangements, including 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 implementation of EPACT and membership in 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, particularly with respect to new, developing or alternative sources of generation.
- 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, 2005	$ 40.80	$ 35.57	$ 37.09	$ 0.37
September 30, 2005	39.84	36.34	39.70	0.35
June 30, 2005	37.00	33.79	36.87	0.35
March 31, 2005	36.34	32.25	34.06	0.35
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

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2005, AEP had approximately 120,000 registered shareholders.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2005	2004	2003	2002	2001
			(in millions)		
STATEMENTS OF OPERATIONS DATA					
Total Revenues	$ 12,111	$ 14,245	$ 14,833	$ 13,641	$ 13,044
Operating Income	$ 1,927	$ 1,983	$ 1,743	$ 1,930	$ 2,289
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,029	$ 1,127	$ 522	$ 485	$ 960
Discontinued Operations, Net of Tax	27	83	(605)	(654)	41
Extraordinary Loss, Net of Tax	(225)	(121)	-	-	(48)
Cumulative Effect of Accounting Changes, Net of Tax	(17)	-	193	(350)	18
Net Income (Loss)	$ 814	$ 1,089	$ 110	$ (519)	$ 971
			(in millions)		
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 39,121	$ 37,294	$ 36,031	$ 34,132	$ 32,993
Accumulated Depreciation and Amortization	14,837	14,493	14,014	13,544	12,655
Net Property, Plant and Equipment	$ 24,284	$ 22,801	$ 22,017	$ 20,588	$ 20,338
Total Assets	$ 36,172	$ 34,636	$ 36,736	$ 36,003	$ 40,452
Common Shareholders' Equity	$ 9,088	$ 8,515	$ 7,874	$ 7,064	$ 8,229
Cumulative Preferred Stocks of Subsidiaries (a) (d)	$ 61	$ 127	$ 137	$ 145	$ 156
Trust Preferred Securities (b)	$ -	$ -	$ -	$ 321	$ 321
Long-term Debt (a) (b)	$ 12,226	$ 12,287	$ 14,101	$ 10,190	$ 9,409
Obligations Under Capital Leases (a)	$ 251	$ 243	$ 182	$ 228	$ 451
COMMON STOCK DATA					
Basic Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.64	$ 2.85	$ 1.35	$ 1.46	$ 2.98
Discontinued Operations, Net of Tax	0.07	0.21	(1.57)	(1.97)	0.13
Extraordinary Loss, Net of Tax	(0.58)	(0.31)	-	-	(0.16)
Cumulative Effect of Accounting Changes, Net of Tax	(0.04)	-	0.51	(1.06)	0.06
Basic Earnings (Loss) Per Share	$ 2.09	$ 2.75	$ 0.29	$ (1.57)	$ 3.01
Weighted Average Number of Basic Shares Outstanding (in millions)	390	396	385	332	322
Market Price Range:					
High	$ 40.80	$ 35.53	$ 31.51	$ 48.80	$ 51.20
Low	$ 32.25	$ 28.50	$ 19.01	$ 15.10	$ 39.25
Year-end Market Price	$ 37.09	$ 34.34	$ 30.51	$ 27.33	$ 43.53
Cash Dividends Paid per Common Share	$ 1.42	$ 1.40	$ 1.65	$ 2.40	$ 2.40
Dividend Payout Ratio (c)	67.9%	50.9%	569.0%	(152.9)%	79.7%
Book Value per Share	$ 23.08	$ 21.51	$ 19.93	$ 20.85	$ 25.54

(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 were classified in 2004 as Current Liabilities because the shares were redeemed in January 2005.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S 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 services 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:

- More than 36,000 megawatts of generating capacity as of December 31, 2005, one of the largest complements of generation in the U.S., the majority of which provides us a significant cost advantage in many of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,026 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 205,483 miles of distribution lines that deliver electricity to customers.
- Substantial coal transportation assets (more than 7,000 railcars, 2,300 barges, 53 towboats and one active coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

BUSINESS STRATEGY

Our mission is to bring comfort to our customers, support business and commerce and build strong communities. Our strategy to achieve our mission is to focus on our core utility business operations. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. Our plan entails designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We intend to 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 operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary, our business strategy calls for us to:

- Respect our people and give them the opportunity to be as successful as they can be.
- Meet the energy needs of our customers in ways that improve their quality of life and protect the environment today and for generations to come.
- Improve the environmental and safety performance of our generating fleet, and grow that fleet.
- Set the standards for safety, efficiency and reliability in our electric transmission and distribution systems.
- Nurture strong and productive relationships with public officials and regulators.
- Provide leadership, integrity and compassion as a corporate citizen to every community we serve.

OUTLOOK FOR 2006

We remain focused on the fundamental earning power of our utilities, and we are committed to maintaining the strength of our balance sheet. To achieve our goals we expect to:

- Obtain permits for our proposed IGCC plants and move forward with the engineering and design for one or more IGCC plants.
- Determine the appropriate generation source for additions to our western fleet.
- Begin preliminary steps to add to our transmission assets to ensure competitive energy prices for our customers in and around congested areas.
- Obtain favorable resolutions to our numerous pending rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.

There are, nevertheless, certain risks and challenges including:

- Regulatory activity in Texas, Ohio, Virginia, West Virginia, Indiana and with the FERC.
- Fuel cost volatility and fuel cost recovery, including related transportation issues.
- Financing and recovering the cost of capital expenditures, including environmental and new technology.
- Wholesale market volatility.
- Plant availability.
- Weather.

Regulatory Activity

In 2005, we filed base rate cases in West Virginia and Kentucky requesting revenue increases totaling approximately $248 million, made a filing in Virginia requesting recovery of $62 million in environmental and reliability costs, filed a depreciation study in Indiana to reduce our book depreciation rates predominantly due to a 20–year nuclear license extension at the Cook Plant, filed an application with the PUCO seeking authority to recover costs related to building and operating an IGCC plant and submitted our $2.4 billion stranded cost recovery filing in Texas. In February 2006, we executed and submitted a settlement agreement in the Kentucky proceeding and are awaiting a final order. In February 2006, we also received a final order in the Texas proceedings and now expect to recover stranded costs of approximately $1.3 billion. Our other outstanding filings are progressing and we expect final orders throughout the first half of 2006.

The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005. Jurisdiction over certain holding company-related activities has been transferred from the SEC to the FERC. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company.

Fuel Costs

Market prices for coal, natural gas and oil continued to increase in 2005 following dramatic increases in 2004. These increasing fuel costs are the result of increasing worldwide demand, supply interruptions and uncertainty, anticipation and ultimate promulgation of clean air rules, transportation constraints and other market factors. We manage price and performance risk 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 prices for our power should allow us to recover our cost of fuel. Accordingly, we should recover approximately 70% of fuel cost increases. The remaining 30% of our fuel costs relate primarily to Ohio and Indiana customers, where we do not have fuel cost recovery mechanisms that will become either active in 2006 or such mechanisms are currently capped. Such percentages are subject to change over time based on fuel cost impacts, fuel caps and freezes and changes to the recovery mechanisms at jurisdictions in our individual operating companies. In West Virginia, we were granted permission to begin deferral accounting for over– or under–recovery of fuel and related costs effective July 1, 2006. In addition, our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans. While these items should help to offset some of the negative impact on our gross margins, we expect an additional eleven to thirteen percent increase in coal costs in 2006.

Capital Expenditures

Our current projections call for capital expenditures of approximately $10.9 billion from 2006-2008, $4.9 billion of which represents committed construction expenditures and $6.0 billion of which represents discretionary expenditures predicated on rate recovery and/or cash generated from operations.

For 2006, $3.7 billion in construction expenditures, excluding allowances for funds used during construction, are forecasted as follows:

	(in millions)
Environmental	$ 1,531
Distribution	790
Transmission	505
Generation	476
New Generation	191
Nuclear	111
Corporate	110

Off-System Sales

In 2006, we expect an approximate 25% decline in gross margins from off-system sales. This decline is primarily due to the sale of TCC generation in 2004 and 2005, increases in planned outages to facilitate our capital improvements and increased demand for electricity from our native load retail customers, all of which reduces the amount of power available for off-system sales.

2005 RESULTS

Our Utility Operations, the core of our business, had a year of continued improvement and favorable operating conditions in 2005. 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. Favorable weather during summer and fall also increased our revenues above expected norms.

Our forecasts indicate that the obligated capacity requirements to meet the growing electricity needs of customers in our eastern seven states will soon exceed the capabilities of our existing fleet of power plants. Our strategy for meeting this growth in demand includes construction of new plants and acquisitions of existing plants. In 2005, we acquired two generating assets, the Waterford Plant and the Ceredo Generating Station, for approximately $320 million. These two assets added 1,326 MW of generating capacity to our eastern fleet.

During 2005, we also announced more than 20 new or renewed wholesale power supply agreements commencing in 2006 or 2007 with various municipalities throughout our service territory. These agreements allow us to remain one of the largest providers of wholesale energy to municipals and cooperatives and demonstrate our commitment to traditional wholesale customers. In 2006, we expect to provide approximately 3,500 MW of full or partial requirement power to 55 municipal utilities and 25 electric cooperatives.

During 2005, we further stabilized our financial strength by:

- Completing asset divestitures of our remaining gas pipeline and storage assets and nuclear generation in Texas resulting in proceeds of approximately $1.6 billion.
- Using the cash flows from our operations to fully fund our qualified pension plans, which also improved our debt to capital ratio to 57.2% at December 31, 2005.
- Receiving upgraded credit ratings from Moody's Investors Service for AEP's short-term and long-term debt.

While we were successful in 2005 in reducing our debt to total capital ratio from 59.1% to 57.2%, we have significant capital expenditures projected for the near-term. Through a combination of cash generated from operations, increased rates as requested in our pending regulatory proceedings and a portion of the Texas stranded cost securitization proceeds, we expect to maintain the strength of our balance sheet and fund our capital expenditure program without material additional leverage.

RESULTS OF OPERATIONS

Segments

In 2005, AEP's principal operating business segments and their major activities were:

- Utility Operations:
  - Generation of electricity for sale to U.S. retail and wholesale customers
  - Electricity transmission and distribution in the U.S.
- Investments – Other:
  - Bulk commodity barging operations, wind farms, independent power producers and other energy supply-related businesses

Our consolidated Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes for the years ended December 31, 2005, 2004 and 2003 were as follows (Earnings and Weighted Average Basic Shares Outstanding in millions):

	2005		2004		2003	
	Earnings	EPS (c)	Earnings	EPS (c)	Earnings	EPS (c)
Utility Operations	$ 1,020	$ 2.61	$ 1,175	$ 2.97	$ 1,223	$ 3.18
Investments – Other	93	0.24	74	0.19	(282)	(0.73)
All Other (a)	(53)	(0.13)	(71)	(0.18)	(129)	(0.34)
Investments – Gas Operations (b)	(31)	(0.08)	(51)	(0.13)	(290)	(0.76)
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,029	$ 2.64	$ 1,127	$ 2.85	$ 522	$ 1.35
Weighted Average Basic Shares Outstanding		390		396		385

(a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.
(b) We sold our remaining gas pipeline and storage assets in 2005.
(c) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in AEP's assets and liabilities as a whole.

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes in 2005 decreased $98 million compared to 2004 primarily due to gains on sales of equity investments in 2004 and a decrease in recorded stranded generation carrying costs income in 2005, as a result of the PUCT decisions related to TCC's True-up Proceeding.

Average basic shares outstanding decreased to 390 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program executed in 2005.

2004 Compared to 2003

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes in 2004 increased $605 million compared to 2003 due to recorded stranded generation carrying costs income at TCC for the years 2002-2004, lower impairments and increased gains realized on the sales of assets. 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.

Average basic 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.

Our results of operations are discussed below according to our operating segments.

Utility Operations

Our Utility Operations include primarily regulated revenues with direct and variable offsetting expenses and net reported commodity trading operations. We believe that a discussion of our Utility Operations segment results on a gross margin basis is most appropriate. Gross margins represent utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	2005	2004	2003
		(in millions)	
Revenues	$ 11,396	$ 10,769	$ 11,160
Fuel and Purchased Power	4,290	3,704	3,844
Gross Margin	7,106	7,065	7,316
Depreciation and Amortization	1,285	1,256	1,250
Other Operating Expenses	3,833	3,778	3,591
Operating Income	1,988	2,031	2,475
Other Income (Expense), Net	103	330	31
Interest Charges and Preferred Stock Dividend Requirements	595	627	673
Income Tax Expense	476	559	610
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,020	$ 1,175	$ 1,223

Summary of Selected Sales and Weather Data
For Utility Operations
For the Years Ended December 31, 2005, 2004 and 2003

	2005	2004	2003
Energy Summary		(in millions of KWH)	
Retail:			
Residential	48,720	45,770	45,308
Commercial	38,605	37,203	36,798
Industrial	53,217	51,484	49,446
Miscellaneous	2,593	3,099	3,026
Subtotal	143,135	137,556	134,578
Texas Retail and Other	615	1,065	2,896
Total	143,750	138,621	137,474
Wholesale	47,784	57,409	47,163
Texas Wires Delivery	26,525	25,581	25,814

	2005	2004	2003
Weather Summary		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,130	2,992	3,219
Normal – Heating (b)	3,088	3,086	3,075
Actual – Cooling (c)	1,152	877	756
Normal – Cooling (b)	969	974	976
Western Region (d)			
Actual – Heating (a)	1,377	1,382	1,554
Normal – Heating (b)	1,615	1,624	1,622
Actual – Cooling (c)	2,386	2,006	2,144
Normal – Cooling (b)	2,150	2,149	2,138

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the 30-year average of degree days.
(c) Eastern Region and Western Region cooling days are calculated on a 65 degree temperature base.
(d) Western Region statistics represent PSO/SWEPCo customer base only.

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2004		$ 1,175
Changes in Gross Margin:		
Retail Margins	67	
Texas Supply	(141)	
Off-system Sales	158	
Transmission Revenues	(57)	
Other Revenues	14	
Total Change in Gross Margin		41
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(95)	
Asset Impairments and Other Related Charges	(39)	
Gain on Sales of Assets, Net	116	
Depreciation and Amortization	(29)	
Taxes Other Than Income Taxes	(37)	
Other Income (Expense), Net	(227)	
Interest and Other Charges	32	
Total Change in Operating Expenses and Other		(279)
Income Tax Expense		83
Year Ended December 31, 2005		$ 1,020

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes decreased $155 million to $1,020 million in 2005. Key drivers of the decrease included a $279 million increase in Operating Expenses and Other, offset in part by a $41 million increase in Gross Margin and an $83 million decrease in Income Tax Expense.

The major components of the net increase in Gross Margin were as follows:

- The increase in Retail Margins from our utility segment over the prior year was 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. The higher usage was primarily weather-related as cooling degree days increased 31% and 19% for the East and West, respectively. This load growth was partially offset by higher delivered fuel costs of approximately $129 million, of which the majority relates to our East companies with inactive fuel clauses.
- Our Texas Supply business experienced a $141 million decrease in gross margin principally due to the sale of almost all of our Texas generation assets to support Texas stranded cost recovery.
- Margins from Off-system Sales for 2005 were $158 million higher than in 2004 due to favorable price margins.
- Transmission Revenues decreased $57 million primarily due to the loss of through-and-out rates as mandated by the FERC.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses increased $95 million due to an $87 million increase in generation expense related to strong retail and wholesale sales and capacity requirements and plant maintenance in 2005 and PJM expenses of $30 million. Additionally, distribution maintenance expense increased $91 million from tree trimming and reliability work. These increases were partially offset by reduced administrative and general expenses of $90 million.
- 2005 included a $39 million impairment related to the retirement of two units at CSPCo's Conesville Plant effective December 29, 2005.
- Gain on Sales of Assets, Net increased $116 million resulting from the receipt of revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase and sale agreement from the sale of our REPs in 2002. Agreement was reached with Centrica in March 2005 resolving disputes back to 2002 on how such amounts were calculated.
- Depreciation and Amortization expense increased $29 million primarily due to a higher depreciable asset base.
- Taxes Other Than Income Taxes increased $37 million due to increased property tax values and assessments and higher state excise taxes due to the increase in taxable KWH sales.
- Other Income (Expense), Net decreased $227 million primarily due to the following:
    - A $321 million decrease related to carrying costs recorded by TCC on its net stranded generation costs and its capacity auction true-up asset. In 2004, TCC booked $302 million of carrying costs income related to 2002 – 2004. Upon receipt of the final order in February 2006 in TCC's True-up Proceeding, we determined that adjustments to those carrying costs were required, resulting in carrying costs expense of $19 million in 2005 for TCC.
    - A $56 million increase related to the establishment of regulatory assets for carrying costs on environmental capital expenditures and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
    - A $20 million increase related to increased interest income and increased AFUDC due to extensive construction activities occurring in 2005.
    - A $14 million increase related to the establishment of regulatory assets for carrying costs on environmental and system reliability capital expenditures for APCo.
- Interest and Other Charges decreased $32 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates and the retirement of debt in 2004 and 2005.
- Income Tax Expense decreased $83 million due to the decrease in pretax income and tax return adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

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 Loss and Cumulative Effect of Accounting Changes
(in millions)

Year Ended December 31, 2003		$ 1,223
Changes in Gross Margin:		
Retail Margins	52	
Texas Supply	(105)	
Wholesale Capacity Auction True-up Revenues	(215)	
Off-System Sales	10	
Other Revenues	7	
Total Change in Gross Margin		(251)
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(171)	
Asset Impairments and Other Related Charges	10	
Depreciation and Amortization	(6)	
Taxes Other Than Income Taxes	(26)	
Carrying Costs	302	
Other Income (Expense), Net	(3)	
Interest and Other Charges	46	
Total Change in Operating Expenses and Other		152
Income Tax Expense		51
Year Ended December 31, 2004		$ 1,175

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes decreased $48 million to $1,175 million in 2004. Key drivers of the decrease include a $251 million decrease in Gross Margin, offset in part by a $152 million decrease in Operating Expenses and Other and a $51 million decrease in Income Tax Expense.

The major components of the net decrease in Gross Margin were as follows:

- The increase in Retail Margins from our utility segment over the prior year was 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 TCC's 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 were no longer recognized, resulting in $215 million of lower regulatory asset deferrals in 2004. For 2003, 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 PUCT's 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 Expenses and Other changed between the years as follows:

- Maintenance and Other Operation expenses increased $171 million due to a $76 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 costs and PJM expenses. 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 Plant restart expenses.
- 2003 included a $10 million impairment at Blackhawk Coal Company, a wholly-owned subsidiary of I&M, which holds western coal reserves.
- Taxes Other Than Income Taxes increased $26 million due to increased property tax values and assessments, higher state excise taxes due to the increase in taxable KWH sales, and favorable prior year franchise tax adjustments.
- Carrying Costs of $302 million represent TCC's debt component of the carrying costs accrued on its net stranded generation costs and its capacity auction true-up asset.
- Interest Charges decreased $46 million from the prior period primarily due to refinancings of higher coupon debt at lower interest rates.
- Income Tax expense decreased $51 million due to the decrease in pretax income and tax return adjustments. See "AEP System Income Taxes" section below for further discussion of fluctuations related to income taxes.

Investments – Other

2005 Compared to 2004

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes from our Investments – Other segment increased from $74 million in 2004 to $93 million in 2005. The increase was partially due to favorable barging activity at MEMCO due to strong demand and a tight supply of barges causing a 45% increase in ton mile freight rates between 2004 and 2005 and various tax adjustments.

2004 Compared to 2003

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes from our Investments – Other segment increased from a loss of $282 million in 2003 to income of $74 million in 2004. The increase was primarily due to gains on sales of assets and equity investments in 2004 of $95 million and impairments of $257 million recorded in 2003.

Other

Parent

2005 Compared to 2004

The parent company's loss decreased $18 million from 2004 primarily due to lower interest expense related to the redemption of $550 million senior unsecured notes in April 2005 and a $20 million provision for penalties in 2004. The decrease was partially offset by lower interest income and guarantee fees related to the repayment of intercompany debt associated with the HPL and UK sales.

2004 Compared to 2003

The parent company's 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. The decrease in loss was offset by lower interest income of $9 million 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.

Investments – Gas Operations

2005 Compared to 2004

The $31 million Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes compares with a $51 million loss recorded for 2004. Current year results include only one month of HPL's operations compared to a full year of HPL operations in the prior year due to the sale of HPL in January of 2005. We also resolved a portion of our outstanding Enron litigation in 2005 resulting in a net of tax settlement cost of approximately $28 million.

2004 Compared to 2003

The Loss Before Discontinued Operations, Extraordinary Loss 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.

AEP System Income Taxes

The decrease in income tax expense of $142 million between 2004 and 2005 is primarily due to a decrease in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by the recording of the tax return adjustments.

The increase in income tax expense of $214 million between 2003 and 2004 is primarily due to an increase in pretax book income, offset in part by the recording of the tax return and tax reserve adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2005, we improved our financial condition as a consequence of the following actions and events:

- We completed approximately $2.7 billion of long-term debt redemptions, including optional redemptions and debt maturities;
- AEP was upgraded to Baa2/P-2 by Moody's Investors Service (Moody's) and we maintained stable credit ratings across the AEP System including our rated subsidiaries; and
- We fully funded our defined benefit qualified pension plans, resulting in the elimination of our minimum pension liability for the qualified plans.

Capitalization ($ in millions)

	December 31, 2005		December 31, 2004	
Common Equity	$ 9,088	42.5%	$ 8,515	40.6%
Preferred Stock	61	0.3	61	0.3
Preferred Stock (Subject to Mandatory Redemption)	-	-	66	0.3
Long-term Debt, including amounts due within one year	12,226	57.2	12,287	58.7
Short-term Debt	10	0.0	23	0.1
Total Capitalization	$ 21,385	100.0%	$ 20,952	100.0%

Our common equity increased due to earnings exceeding the amount of dividends paid in 2005 and a $626 million cash contribution to our qualified pension funds, which allowed us to remove the $330 million charge to equity related to underfunded plans.

As a consequence of the capital changes during 2005 noted above, we improved our ratio of debt to total capital from 59.1% to 57.2% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

The FASB's current pension and postretirement benefit accounting project could have a major negative impact on our debt to capital ratio in future years. The potential change could require the recognition of an additional minimum liability even for fully funded pension and postretirement benefit plans, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 smoothing deferral and amortization of net actuarial gains and losses. If adopted, this could require recognition of a significant net of tax accumulated other comprehensive income reduction to common equity. We cannot predict the effects of the final rule or its effective date.

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, 2005, our available liquidity was approximately $3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,000	May 2007
Revolving Credit Facility	1,500	March 2010
Letter of Credit Facility	200	September 2006
Total	2,700	
Cash and Cash Equivalents	401	
Total Liquidity Sources	3,101	
Less: Letters of Credit Drawn on Credit Facility	91	
Net Available Liquidity	$ 3,010	

During the first half of 2006, subject to market conditions, we plan to amend the terms and increase the size of our $1 billion credit facility expiring in May 2007. We may also amend our $1.5 billion credit facility expiring in March 2010. We also plan to terminate our $200 million letter of credit facility upon its expiration in September 2006. In total, we expect to increase our total credit facilities from $2.7 billion to $3.0 billion.

Debt Covenants and Borrowing Limitations

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 our outstanding debt and other capital is contractually defined. At December 31, 2005, this percentage was 54.2%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 31, 2005, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations 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 outstanding amounts payable.

Our $1 billion revolving credit facility, which matures in May 2007, generally prohibits new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under this facility if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper. Under the $1.5 billion revolving credit facility, which matures in March 2010, we may borrow despite a material adverse change.

Under a regulatory order, AEP's utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts 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, 2005, all utility subsidiaries were in compliance with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2005, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 383 consecutive quarters. The Board of Directors increased the quarterly dividend from $0.35 to $0.37 per share in October 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. In 2005, we announced criteria that will be used to make future dividend recommendations to the Board of Directors.

Credit Ratings

Moody's upgraded AEP's short and long-term debt ratings during 2005. Our current credit ratings are as follows:

	Moody's	S&P	Fitch
AEP Short Term Debt	P-2	A-2	F-2
AEP Senior Unsecured Debt	Baa2	BBB	BBB

If we or any of our 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 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.

	2005	2004	2003
		(in millions)	
Cash and cash equivalents at beginning of period	$ 320	$ 778	$ 1,085
Net Cash Flows From Operating Activities	1,877	2,711	2,500
Net Cash Flows Used For Investing Activities	(1,005)	(329)	(2,298)
Net Cash Flows Used For Financing Activities	(791)	(2,840)	(509)
Net Increase (Decrease) in Cash and Cash Equivalents	81	(458)	(307)
Cash and cash equivalents at end of period	$ 401	$ 320	$ 778

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, 2005, we had credit facilities totaling $2.5 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. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders.

Operating Activities

	2005	2004	2003
		(in millions)	
Net Income	$ 814	$ 1,089	$ 110
Plus: (Income) Loss From Discontinued Operations	(27)	(83)	605
Income From Continuing Operations	787	1,006	715
Noncash Items Included in Earnings	1,714	1,471	1,939
Changes in Assets and Liabilities	(624)	234	(154)
Net Cash Flows From Operating Activities	$ 1,877	$ 2,711	$ 2,500

The key drivers of the decrease in cash from operations in 2005 are the pension contribution of $626 million and an increase in under-recovered fuel of $239 million.

2005 Operating Cash Flow

Net Cash Flows From Operating Activities were approximately $1.9 billion in 2005. We produced Income from Continuing Operations of $787 million. Income from Continuing Operations included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. We made contributions of $626 million to our pension trusts. Under-recovered fuel costs increased due to the higher cost of fuel, especially natural gas. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking to recover our increased fuel costs. 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 these asset and liability accounts relates to a number of items; the most significant are a $140 million cash increase from Accounts Payable due to higher fuel and allowance acquisition costs not paid at December 31, 2005 and an increase in Customer Deposits of $157 million.

2004 Operating Cash Flow

During 2004, Net Cash Flows From Operating Activities were $2.7 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 TCC's stranded generation costs. We realized gains of $157 million on sales of assets, primarily the IPPs and our South Coast equity investment. We made $231 million of contributions to our pension trusts.

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 $430 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.

2003 Operating Cash Flow

Net Cash Flows From Operating Activities were $2.5 billion in 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 were:

- 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 TCC's True-up Proceeding.
- Net changes in accounts receivable and accounts payable of $291 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 are a component of our Texas True-up Proceedings.

Investing Activities

	2005	2004	2003
		(in millions)	
Construction Expenditures	$ (2,404)	$ (1,637)	$ (1,322)
Change in Other Temporary Cash Investments, Net	76	32	(91)
Investment in Discontinued Operations, Net	-	(59)	(615)
Purchases of Investment Securities	(8,836)	(1,574)	(1,022)
Sales of Investment Securities	8,934	1,620	736
Acquisitions of Assets	(360)	-	-
Proceeds from Sales of Assets	1,606	1,357	82
Other	(21)	(68)	(66)
Net Cash Flows Used for Investing Activities	$ (1,005)	$ (329)	$ (2,298)

Net Cash Flows Used For Investing Activities were $1.0 billion in 2005 primarily due to Construction Expenditures being partially offset by the proceeds from the sales of HPL and STP. The sales were part of an announced plan to divest noncore investments and assets and a requirement of collecting stranded costs in Texas. Construction Expenditures increased due to our environmental investment plan.

We purchase auction rate securities and variable rate demand notes with cash available for short-term investments. During 2005, we purchased $8.8 billion of investments and received $8.9 billion of proceeds from their sale. These amounts also include purchases and sales within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $329 million in 2004. We funded our construction expenditures primarily with cash generated by operations. Our construction expenditures of $1.6 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.

Net Cash Flows Used For Investing Activities were $2.3 billion in 2003 for increased investments in our U.K. operations and environmental and normal capital expenditures.

We forecast $3.7 billion of construction expenditures for 2006. 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. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	2005	2004	2003
		(in millions)	
Issuance of Common Stock	$ 402	$ 17	$ 1,142
Repurchase of Common Stock	(427)	-	-
Issuance/Retirement of Debt, Net	(91)	(2,238)	(743)
Dividends Paid on Common Stock	(553)	(555)	(618)
Other	(122)	(64)	(290)
Net Cash Flows Used for Financing Activities	$ (791)	$ (2,840)	$ (509)

In 2005, we used $791 million of cash to pay dividends, retire preferred stock and reduce debt.

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 $509 million during 2003. The proceeds from the issuance of common stock were used to reduce outstanding debt and minority interest in a finance subsidiary.

The following financing activities occurred during 2005:

Common Stock:

- In March 2005, we repurchased 12,500,000 shares of common stock for $427 million.
- In August 2005, we issued 8,435,200 shares of common stock to settle part of a forward contract in equity units issued in 2002.
- During 2005, we issued 1,925,485 shares of common stock under our incentive compensation plans and received net proceeds of $57 million.

Debt:

- During 2005, we issued approximately $2.7 billion of long-term debt, including approximately $676 million of pollution control revenue bonds. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions, asset acquisitions and construction programs.
- During 2005, we entered into $1,090 million of interest rate derivatives and unwound $1,365 million of such transactions. The unwinds resulted in a net cash expenditure of $25.5 million. As of December 31, 2005, we had in place interest rate hedge transactions with a notional amount of $125 million in order to hedge a portion of anticipated 2006 issuances.
- At December 31, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. As of December 31, 2005, 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 $25 million in January 2005 and the weighted average interest rate of commercial paper outstanding during the year was 2.50%.

Our plans for 2006 include the following:

- In February of 2006, APCo issued obligations relating to auction rate pollution control bonds in the amount of $50 million. The new bonds bear interest at a 28-day auction rate. The proceeds from this issuance will contribute to our investment in environmental equipment.
- In 2006, our plan for capital investment will require additional funding from the capital markets.

Off-balance Sheet Arrangements

We enter 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:

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, in accordance with GAAP, are not required to consolidate these entities. 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.

AEP Credit's sale of receivables agreement expires August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 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 as of December 31, 2005.

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. 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. 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, 2005, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have 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, 2005:

Contractual Cash Obligations	Payments Due by Period (in millions) Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 10	$ -	$ -	$ -	$ 10
Interest on Fixed Rate Portion of Long-term Debt (b)	552	939	768	3,982	6,241
Fixed Rate Portion of Long-term Debt (c)	1,131	1,650	1,568	6,017	10,366
Variable Rate Portion of Long-term Debt (d)	22	168	583	1,145	1,918
Capital Lease Obligations (e)	73	113	45	93	324
Noncancelable Operating Leases (e)	313	552	500	2,018	3,383
Fuel Purchase Contracts (f)	2,276	3,092	2,602	6,311	14,281
Energy and Capacity Purchase Contracts (g)	306	431	349	709	1,795
Construction Contracts for Capital Assets (h)	1,267	460	-	-	1,727
Total	$ 5,950	$ 7,405	$ 6,415	$ 20,275	$ 40,045

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 17. Represents principal only excluding interest.
(d) See Note 17. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.10% and 6.35% at December 31, 2005.
(e) See Note 16.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) 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, 2005, 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) (b)	$ 130	$ -	$ -	$ -	$ 130
Guarantees of the Performance of Outside Parties (b)	8	-	25	105	138
Guarantees of our Performance (c)	1,483	936	688	8	3,115
Transmission Facilities for Third Parties (d)	44	47	-	-	91
Total Commercial Commitments	$ 1,665	$ 983	$ 713	$ 113	$ 3,474

(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 $130 million with maturities ranging from February 2006 to March 2007. As the parent of all of these subsidiaries, AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties if these letters of credit are drawn.
(b) See "Guarantees of Third-party Obligations" section of Note 8.
(c) We have issued performance guarantees and indemnifications for energy trading, Dow Chemical Company financing, International Marine Terminal Pollution Control Bonds and various 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

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 if the Texas retail market developed increased earnings opportunities. In 2005, upon resolution of various contractual matters with Centrica, we received payments from our share in earnings of $45 million and $70 million for 2003 and 2004, respectively. The 2005 and 2006 payments are contingent on Centrica's future operating results and are capped at $70 million and $20 million for 2005 and 2006, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap. We expect to receive the 2005 payment in March of 2006. (see "Texas REPs" section of Note 10).

SIGNIFICANT FACTORS

AEP Interstate Project

On January 31, 2006, we filed with the FERC and PJM a proposal to build a new 765 kV transmission line stretching from West Virginia to New Jersey. The proposed project, which will span approximately 550 miles, is designed to reduce PJM congestion costs by substantially improving west-east peak transfer capability by approximately 5,000 MW and reducing transmission line losses by up to 280 MW. It will also enhance reliability of the Eastern transmission grid. A new subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected cost for the project is $3 billion, which may be shared with other stakeholders, and the project is subject to regulatory approval and recovery mechanisms. A projected in-service date is 2014, subject to PJM and FERC approval, assuming three years to site and acquire rights-of-way and five years to construct the line. We also filed with the DOE to have the proposed route designated a National Interest Electric

Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.

Texas Regulatory Activity

Texas Restructuring

The stranded cost quantification process in Texas continued in 2005 with TCC filing its True-Up Proceeding in May seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined TCC's stranded costs to be $1.5 billion, including carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. TCC adjusted its December 2005 books to reflect the final order. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded as a pretax extraordinary loss.

TCC believes that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT has issued in implementing that statute. TCC intends to seek rehearing of the PUCT's rulings. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any requested rehearings or appeals.

TCC anticipates filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which TCC anticipates will be negative, and as such will reduce rates to customers through a negative competition transition charge (CTC). The estimated amount for rate reduction to customers, including carrying costs through August 31, 2006, is approximately $475 million. TCC will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an accumulated deferred federal income tax (ADFIT) benefit related to TCC's stranded generation cost, and the positive wholesale capacity auction true-up balance. TCC anticipates making a filing to implement its CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

	in millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	**$ 1,275**
Unrecognized but Recoverable Equity Carrying Costs and Other	200
Estimated January 2006 – August 2006 Carrying Costs	144
Securitization Issuance Costs	24
Net Other Recoverable True-up Amounts (a)	161
Estimated Securitization Request	**$ 1,804**

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

If we determine in future securitization and competition transition charge proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. See "Texas Restructuring" section of Note 6 following our financial statements for a discussion of the $200 million difference between the final order and our recorded balance.

Integrated Gasification Combined Cycle (IGCC) Power Plants

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSP. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover, or refund, in distribution rates any difference between the Ohio companies' market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. As of December 31, 2005, we have deferred $7 million of pre-construction IGCC costs for the Ohio companies. These costs primarily relate to an agreement with GE Energy and Bechtel Corporation to begin the front-end engineering design process.

In January 2006, APCo filed an application with the WVPSC seeking authority to construct a 600MW IGCC electric generating unit in West Virginia. If built, the unit would be located next to APCo's Mountaineer Plant.

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 (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively "the Plans."

The following table shows the net periodic cost for our Pension Plans and Postretirement Plans:

	2005	2004
	(in millions)	
Net Periodic Cost:		
Pension Plans	$ 61	$ 40
Postretirement Plans	109	141
Assumed Rate of Return:		
Pension Plans	8.75%	8.75%
Postretirement Plans	8.37%	8.35%

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 2005, of approximately 10%. We anticipate that the investment managers we employ for the Plans will generate long-term returns averaging 8.50%.

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:

	Pension		Other Postretirement Benefit Plans		
	2005 Actual Asset Allocation	2006 Target Asset Allocation	2005 Actual Asset Allocation	2006 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	66%	70%	68%	66%	10.00%
Fixed Income	25%	28%	30%	31%	5.25%
Cash and Cash Equivalents	9%	2%	2%	3%	3.50%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. Because we made a $320 million discretionary contribution to the Qualified Plans at the end of 2005, the actual 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 2006. We believe that 8.50% 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 7.76% and 12.90% for the twelve months ended December 31, 2005 and 2004, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions 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, 2005, we had cumulative losses of approximately $37 million that 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 is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching 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, 2005 under this method was 5.50% for the Pension Plans and 5.65% 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 8.50%, a discount rate of 5.50% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $73 million, $76 million and $56 million in 2006, 2007 and 2008, respectively. We estimate Postretirement Plan costs will approximate $99 million, $102 million and $97 million in 2006, 2007 and 2008, 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 Management's Financial Discussion and Analysis of Results of Operations.

The value of our Pension Plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004 primarily due to discretionary contributions to the Qualified Plans. The Qualified Plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 million in benefits). The value of our Postretirement Plans' assets increased to $1.2 billion at December 31, 2005 from $1.1 billion at December 31, 2004. The Postretirement Plans paid $118 million in benefits to plan participants during 2005.

For our pension plans, the accumulated benefit obligation in excess of plan assets was $81 million and $474 million at December 31, 2005 and 2004, respectively. While our non-qualified pension plans are unfunded, our qualified pension plans are fully funded as of December 31, 2005.

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 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

We made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet our goal of fully funding all Qualified 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

In the ordinary course of business, AEP and its subsidiaries are involved in a substantial amount of employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings see Note 4 – Rate Matters, Note 6 – Customer Choice and Industry and Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect the results of operations of AEP and its subsidiaries.

See discussion of the Environmental Litigation within "Significant Factors - Environmental Matters."

Environmental Matters

We have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) 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 (CO_2) emissions to address concerns about global climate change.

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. All of these matters are discussed below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality, and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as "national ambient air quality standards" or NAAQS.

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO_2 and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO_2 and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. The Federal EPA is currently reconsidering certain aspects of the final CAIR, and the rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which our power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x

emissions in order to comply with CAIR. The Federal EPA is currently reconsidering certain aspects of the final CAMR, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO_2 emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program has encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the "Regional Haze" program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above will require us to make significant additional investments, some of which are estimable. However, many of the rules described above are the subject of reconsideration by the Federal EPA, have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Our estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and our selected compliance alternatives. In short, we cannot estimate our compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

We installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at our eastern power plants over the past several years to comply with NO_x requirements in various SIPs. Additional NO_x requirements associated with CAIR and CAMR will result in additional investments between 2006 and 2010, estimated to be $191 million, including completion of SCRs on an additional 1900 MW of capacity.

We are complying with Acid Rain Program SO_2 requirements by installing scrubbers, other controls, and using alternate fuels. We also use SO_2 allowances we receive through Acid Rain Program allocations, purchase at the annual Federal EPA auction, and purchase in the market. Decreasing allowance allocations, our diminishing SO_2 allowance bank, and increasing allowance costs will require us to install additional controls on our power plants. In addition, under CAIR and CAMR we will be required to install additional controls by 2010. We plan to install by 2010 additional scrubbers on 8,700 MW to comply with current, CAIR and CAMR requirements. From 2006 to 2010, we estimate that the additional investment in scrubbers will be approximately $2.8 billion. We will also incur additional operation and maintenance expenses during 2006 and subsequent years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, we expect to incur additional costs for pollution control technology retrofits between 2011 and 2020 of approximately $1 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on our units; (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

We will seek recovery of expenditures for pollution control technologies, replacement or additional 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.

Clean Water Act Regulations

In July 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for our plants. Any capital costs incurred to meet these standards will likely be incurred between 2008 and 2010. We are required to undertake site-specific studies, and we may propose site-specific compliance or mitigation measures that could significantly change this estimate. These studies are currently underway, and the rule has been challenged in the courts.

Potential Regulation of CO_2 Emissions

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 in November 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. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none has passed either house of Congress.

The Federal EPA has stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. While mandatory requirements to reduce CO_2 emissions at our power plants do not appear to be imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed against other nonaffiliated utilities in 1999 and 2000. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has been completed, but no decision has been issued.

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.

Courts that have considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, have reached different conclusions. Similarly, courts that have considered whether the activities at issue increased emissions from the power plants have reached different results. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability we might have 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, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

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 that 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 future 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 AEP's 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 our 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 regulated revenues from our customers 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 review the 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 electric utility revenues included in Revenue were $28 million, $22 million and $13 million for the years ended December 31, 2005, 2004 and 2003, respectively. Accrued Unbilled Revenues on the Balance Sheets were $374 million and $665 million as of December 31, 2005 and 2004, respectively.

Assumptions and Approach Used – The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current month's billed KWH plus the prior month's 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 AEP East companies, KGPCo and WPCo. The annual load research study, based on a sample of accounts, is an additional verification of the unbilled estimate. The unbilled estimate is adjusted annually, if necessary, 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% of the Accrued Unbilled Revenues on the Balance Sheets.

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, involve 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 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 into 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 as necessary 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 evaluations of long-lived assets may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. 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 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 of the Notes to Consolidated Financial Statements, we made our best estimate of fair value using valuation methods based on the most current information at that time. We have been divesting certain noncore assets and their sales values can vary from the recorded fair value as described in Note 10 of the Notes to Consolidated Financial Statements. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's 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, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan 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, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan 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, 2005 Benefit Obligations:				
Discount Rate	$ (198)	$ 207	$ (116)	$ 124
Salary Scale	30	(30)	4	(4)
Cash Balance Crediting Rate	(16)	17	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	112	(106)
Effect on 2005 Periodic Cost:				
Discount Rate	(10)	10	(10)	10
Salary Scale	6	(5)	1	(1)
Cash Balance Crediting Rate	3	(2)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(17)
Expected Return on Assets	(18)	18	(5)	5

New Accounting Pronouncements

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. In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R. We implemented SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required 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 is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

We adopted FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47) during the fourth quarter of 2005. We completed a review of our FIN 47 conditional asset retirement obligations and concluded that we have legal liabilities for asbestos removal and disposal in general building and generating plants. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to a regulatory liability. We recorded an unfavorable cumulative effect of $26 million ($17 million net of tax) for our non-regulated operations related to asbestos removal in the Utility Operations segment.

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty" focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29 "Accounting for Nonmonetary Transactions" if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on our financial statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, our Utility Operations segment is exposed to certain market risks. 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.

Our Investment – Gas Operations segment continues to hold forward gas contracts that were not sold with the gas pipeline and storage assets. These contracts are primarily financial derivatives with some physical contracts, which will gradually liquidate and completely expire in 2011. Our risk objective is to keep these positions risk neutral through maturity.

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, coal, and emissions and to a lesser degree other commodities. 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 risk management staff. When risk management activities exceed certain predetermined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

We have established policies and procedures that 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, senior executives, and other 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 applicable to our business activities. The following tables provide information on our risk management activities.

Mark-to-Market Risk Management Contract Net Assets (Liabilities)

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2005 and the reasons for changes in our total MTM value included in our balance sheet as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet
December 31, 2005
(in millions)

	Utility Operations	Investments - Gas Operations	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	$ 705	$ 210	$ 915	$ 11	$ 926
Noncurrent Assets	593	291	884	2	886
Total Assets	1,298	501	1,799	13	1,812
Current Liabilities	(661)	(223)	(884)	(22)	(906)
Noncurrent Liabilities	(422)	(297)	(719)	(4)	(723)
Total Liabilities	(1,083)	(520)	(1,603)	(26)	(1,629)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 215	$ (19)	$ 196	$ (13)	$ 183

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2004	$ 277	$ -	$ (12)	$ 265
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(81)	(21)	12	(90)
Fair Value of New Contracts at Inception When Entered During the Period (a)	4	-	-	4
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	(6)	-	-	(6)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	19	2	-	21
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2	-	-	2
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2005	$ 215	$ (19)	$ -	196
Net Cash Flow and Fair Value Hedge Contracts				(13)
Ending Net Risk Management Assets at December 31, 2005				$ 183

(a) 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.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(c) "Change in Fair Value 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.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)

The following table presents:

- The method of measuring 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, to give 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, 2005
(in millions)

	2006	2007	2008	2009	2010	After 2010	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 42	$ 8	$ 5	$ -	$ -	$ -	$ 55
Prices Provided by Other External Sources – OTC Broker Quotes (a)	56	68	51	26	-	-	201
Prices Based on Models and Other Valuation Methods (b)	(54)	(22)	(11)	12	30	4	(41)
Total	$ 44	$ 54	$ 45	$ 38	$ 30	$ 4	$ 215
Investments – Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (15)	$ 11	$ -	$ -	$ -	$ -	$ (4)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	5	(8)	-	-	-	-	(3)
Prices Based on Models and Other Valuation Methods (b)	(3)	(1)	(2)	(4)	(3)	1	(12)
Total	$ (13)	$ 2	$ (2)	$ (4)	$ (3)	$ 1	$ (19)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ 27	$ 19	$ 5	$ -	$ -	$ -	$ 51
Prices Provided by Other External Sources – OTC Broker Quotes (a)	61	60	51	26	-	-	198
Prices Based on Models and Other Valuation Methods (b)	(57)	(23)	(13)	8	27	5	(53)
Total	$ 31	$ 56	$ 43	$ 34	$ 27	$ 5	$ 196

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is 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.

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, 2005

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	24
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	48
	Physical Forwards	AEP West	48
	Physical Forwards	West Coast	48
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	36
Coal	Physical Forwards	PRB, NYMEX, CSX	36

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Consolidated Balance Sheets

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 the use of interest rate derivative transactions in order to manage interest rate risk related to existing debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2004 to December 31, 2005. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2005
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance in AOCI, December 31, 2004	$ 23	$ (23)	$ -
Changes in Fair Value	(3)	(2)	(5)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(26)	4	(22)
Ending Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ (5)	$ (2)	$ (7)

Credit Risk

We limit credit risk in our marketing and trading activities 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 Moody's Investors Service, Standard & Poor's 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. As of December 31, 2005, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 12.05%, expressed in terms of net MTM assets and net receivables. As of December 31, 2005, 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	$ 930	$ 330	$ 600	1	$ 111
Split Rating	3	-	3	2	3
Noninvestment Grade	242	152	90	3	80
No External Ratings:					
Internal Investment Grade	173	-	173	1	116
Internal Noninvestment Grade	18	2	16	3	12
Total	$ 1,366	$ 484	$ 882	10	$ 322

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, 2008. 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, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
December 31, 2005

	2006	2007	2008
Estimated Plant Output Hedged	91%	88%	90%

VaR Associated with Risk Management Contracts

Commodity Price Risk

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, 2005, 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, 2005 (in millions)				December 31, 2004 (in millions)			
End	High	Average	Low	End	High	Average	Low
$3	$5	$3	$1	$3	$19	$5	$1

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.

Interest Rate Risk

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 $615 million at December 31, 2005 and $601 million at December 31, 2004. 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 financial position.

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, 2005 and 2004, and the related consolidated statements of operations, cash flows, and changes in common shareholders' equity and comprehensive income (loss), for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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 FIN 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005. As discussed in Notes 8, 16 and 17 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. As discussed in Note 11 to the consolidated financial statements, the Company adopted 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, 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 27, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus,Ohio
February 27, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited management's assessment, included in the accompanying *Management's 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, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

Because of 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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated 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, 2005, based on the criteria established in *Internal Control—Integrated 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 schedule as of and for the year ended December 31, 2005 of the Company and our reports dated February 27, 2006 expressed an unqualified opinion on those financial statements (and with respect to the report on those financial statements, included an explanatory paragraph concerning the Company's adoption of new accounting pronouncements in 2003, 2004 and 2005) and the financial statement schedule.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2006

MANAGEMENT'S 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. AEP's 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 Company's internal control over financial reporting as of December 31, 2005. 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 Company's internal control over financial reporting was effective as of December 31, 2005.

AEP's independent registered public accounting firm has issued an attestation report on our assessment of the Company's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2005, 2004 and 2003
(in millions, except per-share amounts)

	2005	2004	2003
REVENUES			
Utility Operations	$ 11,193	$ 10,664	$ 11,030
Gas Operations	463	3,068	3,100
Other	455	513	703
TOTAL	12,111	14,245	14,833
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,592	3,059	3,147
Purchased Energy for Resale	687	670	707
Purchased Gas for Resale	256	2,807	2,850
Maintenance and Other Operation	3,649	3,700	3,776
Asset Impairments and Other Related Charges	39	-	650
Gain/Loss on Disposition of Assets, Net	(120)	(4)	(48)
Depreciation and Amortization	1,318	1,300	1,307
Taxes Other Than Income Taxes	763	730	701
TOTAL	10,184	12,262	13,090
OPERATING INCOME	1,927	1,983	1,743
Investment Income	105	33	25
Carrying Costs	55	302	-
Allowance For Equity Funds Used During Construction	21	15	14
Investment Value Losses	(7)	(15)	(70)
Gain on Disposition of Equity Investments, Net	56	153	-
INTEREST AND OTHER CHARGES			
Interest Expense	697	781	814
Preferred Stock Dividend Requirements of Subsidiaries	7	6	9
Minority Interest in Finance Subsidiary	-	-	17
TOTAL	704	787	840
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	1,453	1,684	872
Income Tax Expense	430	572	358
Minority Interest Expense	4	3	2
Equity Earnings of Unconsolidated Subsidiaries	10	18	10
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES	1,029	1,127	522
DISCONTINUED OPERATIONS, Net of Tax	27	83	(605)
EXTRAORDINARY LOSS, Net of Tax	(225)	(121)	-
CUMULATIVE EFFECT OF ACCOUNTING CHANGES, Net of Tax			
Accounting for Risk Management Contracts	-	-	(49)
Asset Retirement Obligations	(17)	-	242
NET INCOME	$ 814	$ 1,089	$ 110
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	390	396	385
BASIC EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.64	$ 2.85	$ 1.35
Discontinued Operations, Net of Tax	0.07	0.21	(1.57)
Extraordinary Loss, Net of Tax	(0.58)	(0.31)	-
Cumulative Effect of Accounting Changes, Net of Tax	(0.04)	-	0.51
TOTAL BASIC EARNINGS PER SHARE	$ 2.09	$ 2.75	$ 0.29
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	391	396	385
DILUTED EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 2.63	$ 2.85	$ 1.35
Discontinued Operations, Net of Tax	0.07	0.21	(1.57)
Extraordinary Loss, Net of Tax	(0.58)	(0.31)	-
Cumulative Effect of Accounting Changes, Net of Tax	(0.04)	-	0.51
TOTAL DILUTED EARNINGS PER SHARE	$ 2.08	$ 2.75	$ 0.29
CASH DIVIDENDS PAID PER SHARE	$ 1.42	$ 1.40	$ 1.65

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in millions)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 401	$ 320
Other Temporary Cash Investments	127	275
Accounts Receivable:		
Customers	826	830
Accrued Unbilled Revenues	374	665
Miscellaneous	51	84
Allowance for Uncollectible Accounts	(31)	(77)
Total Receivables	1,220	1,502
Fuel, Materials and Supplies	726	852
Risk Management Assets	926	737
Margin Deposits	221	113
Regulatory Asset for Under-Recovered Fuel Costs	197	7
Other	127	190
TOTAL	3,945	3,996
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,653	15,969
Transmission	6,433	6,293
Distribution	10,702	10,280
Other (including gas, coal mining and nuclear fuel)	3,116	3,593
Construction Work in Progress	2,217	1,159
Total	39,121	37,294
Accumulated Depreciation and Amortization	14,837	14,493
TOTAL - NET	24,284	22,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,262	3,594
Securitized Transition Assets and Other	593	642
Spent Nuclear Fuel and Decommissioning Trusts	1,134	1,053
Investments in Power and Distribution Projects	97	154
Goodwill	76	76
Long-term Risk Management Assets	886	470
Employee Benefits and Pension Assets	1,105	422
Other	746	800
TOTAL	7,899	7,211
Assets Held for Sale	44	628
TOTAL ASSETS	$ 36,172	$ 34,636

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
	(In millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,144	$ 1,055
Short-term Debt	10	23
Long-term Debt Due Within One Year	1,153	1,279
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	66
Risk Management Liabilities	906	608
Accrued Taxes	651	611
Accrued Interest	183	185
Customer Deposits	571	414
Other	842	749
TOTAL	5,460	4,990
NONCURRENT LIABILITIES		
Long-term Debt	11,073	11,008
Long-term Risk Management Liabilities	723	329
Deferred Income Taxes	4,810	4,819
Regulatory Liabilities and Deferred Investment Tax Credits	2,747	2,522
Asset Retirement Obligations	936	827
Employee Benefits and Pension Obligations	355	730
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	157	166
Deferred Credits and Other	762	419
TOTAL	21,563	20,820
Liabilities Held for Sale	-	250
TOTAL LIABILITIES	27,023	26,060
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		
2005 / 2004		
Shares Authorized 600,000,000 / 600,000,000		
Shares Issued 415,218,830 / 404,858,145		
(21,499,992 and 8,999,992 shares were held in treasury at December 31, 2005 and 2004, respectively)	2,699	2,632
Paid-in Capital	4,131	4,203
Retained Earnings	2,285	2,024
Accumulated Other Comprehensive Income (Loss)	(27)	(344)
TOTAL	9,088	8,515
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 36,172	$ 34,636

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, 2005, 2004 and 2003
(in millions)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 814	$ 1,089	$ 110
(Income) Loss from Discontinued Operations	(27)	(83)	605
Income from Continuing Operations	787	1,006	715
Adjustments for Noncash Items:			
Depreciation and Amortization	1,318	1,300	1,307
Accretion of Asset Retirement Obligations	63	64	59
Deferred Income Taxes	65	291	163
Deferred Investment Tax Credits	(32)	(29)	(33)
Cumulative Effect of Accounting Changes, Net	17	-	(193)
Asset Impairments, Investment Value Losses and Other Related Charges	46	15	720
Carrying Costs	(55)	(302)	-
Extraordinary Loss	225	121	-
Amortization of Deferred Property Taxes	(17)	(3)	(2)
Amortization of Cook Plant Restart Costs	-	-	40
Mark-to-Market of Risk Management Contracts	84	14	(122)
Pension Contributions to Qualified Plan Trusts	(626)	(231)	(58)
Over/Under Fuel Recovery	(239)	96	239
Gain on Sales of Assets and Equity Investments, Net	(176)	(157)	(48)
Change in Other Noncurrent Assets	(28)	(100)	(24)
Change in Other Noncurrent Liabilities	3	196	(73)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(7)	280	473
Fuel, Materials and Supplies	(20)	33	(52)
Accounts Payable	140	(306)	(764)
Taxes Accrued	48	427	87
Customer Deposits	157	35	194
Other Current Assets	(56)	(47)	(2)
Other Current Liabilities	180	8	(126)
Net Cash Flows From Operating Activities	1,877	2,711	2,500
INVESTING ACTIVITIES			
Construction Expenditures	(2,404)	(1,637)	(1,322)
Change in Other Temporary Cash Investments, Net	76	32	(91)
Investment in Discontinued Operations, Net	-	(59)	(615)
Purchases of Investment Securities	(8,836)	(1,574)	(1,022)
Sales of Investment Securities	8,934	1,620	736
Acquisitions of Assets	(360)	-	-
Proceeds from Sales of Assets	1,606	1,357	82
Other	(21)	(68)	(66)
Net Cash Flows Used For Investing Activities	(1,005)	(329)	(2,298)
FINANCING ACTIVITIES			
Issuance of Common Stock	402	17	1,142
Repurchase of Common Stock	(427)	-	-
Issuance of Long-term Debt	2,651	682	4,761
Change in Short-term Debt, Net	(13)	(409)	(2,797)
Retirement of Long-term Debt	(2,729)	(2,511)	(2,707)
Dividends Paid on Common Stock	(553)	(555)	(618)
Other	(122)	(64)	(290)
Net Cash Flows Used For Financing Activities	(791)	(2,840)	(509)
Net Increase (Decrease) in Cash and Cash Equivalents	81	(458)	(307)
Cash and Cash Equivalents at Beginning of Period	320	778	1,085
Cash and Cash Equivalents at End of Period	$ 401	$ 320	$ 778
CASH FLOWS FROM DISCONTINUED OPERATIONS (Revised - see Note 1)			
Operating Activities	$ -	$ (3)	$ 12
Investing Activities	-	(10)	(13)
Financing Activities	-	-	(9)
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	-	(13)	(10)
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	-	13	23
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ -	$ 13

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004, and 2003
(in millions)

	Common Stock				Accumulated Other	
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Total
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						
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						7,344
COMPREHENSIVE INCOME						
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
Issuance of Common Stock	10	67	335			402
Common Stock Dividends				(553)		(553)
Repurchase of Common Stock			(427)			(427)
Other			20			20
TOTAL						7,957
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(6)	(6)
Cash Flow Hedges, Net of Tax of $15					(27)	(27)
Securities Available for Sale, Net of Tax of $11					20	20
Minimum Pension Liability, Net of Tax of $175					330	330
NET INCOME				814		814
TOTAL COMPREHENSIVE INCOME						1,131
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER, INC. AND SUBSIDIARY COMPANIES
INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes
3. Goodwill and Other Intangible Assets
4. Rate Matters
5. Effects of Regulation
6. Customer Choice and Industry Restructuring
7. Commitments and Contingencies
8. Guarantees
9. Company-wide Staffing and Budget Review
10. Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Other Losses
11. Benefit Plans
12. Stock-Based Compensation
13. Business Segments
14. Derivatives, Hedging and Financial Instruments
15. Income Taxes
16. Leases
17. Financing Activities
18. Jointly-Owned Electric Utility Plant
19. Unaudited Quarterly Financial Information

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of our electric utility operating companies is the generation, transmission and distribution of electric power. Two of those electric utility operating companies are completing the final stage of exiting the generation business. Two of our electric utility operating companies provide only transmission and distribution services. One of our companies is an electricity generation business. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies 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.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated independent power and cogeneration facilities, coal mining and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale power markets. Wholesale power markets are generally market-based and are not cost-based regulated unless a wholesaler negotiates and files a cost-based rate contract with the FERC or 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 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).

For the periods presented, we were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (PUHCA 1935). The Energy Policy Act of 2005 repealed PUHCA 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA 2005). With the repeal of PUHCA 1935, the SEC no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over holding company-related activities has been transferred to the FERC. Regulations and required reporting under PUHCA 2005 are reduced compared to those under PUHCA 1935. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records of any company within a holding company system.

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 Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Operations. We also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) "Consolidation of Variable Interest Entities" (FIN 46R) (see "Guarantees of Third Party Obligations" section of Note 8 and "Gavin Scrubber Financing Arrangement" section of Note 16). 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 our proportionate share of the assets and liabilities 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 and in Arkansas by SWEPCo in September 1999. 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, valuation 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 and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately 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 nonregulated operations and other investments are stated at 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 our plants are included in operating expenses.

We implemented SFAS 143 effective January 1, 2003 and FIN 47 effective December 31, 2005 (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.

Property, Plant and Equipment is disclosed as regulated/nonregulated by functional class within the Depreciation, Depletion and Amortization section below.

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)		(%)	(in years)	(in millions)		(%)	(in years)
Production	$ 7,411	$ 4,166	2.7 - 3.8	30 - 120	$ 9,242	$ 4,019	2.6 - 3.3	20 - 120
Transmission	6,433	2,280	1.7 - 3.0	25 - 75	-	-	N.M.	N.M.
Distribution	10,702	3,085	3.1 - 4.1	10 - 75	-	-	N.M.	N.M.
CWIP	1,341	(14)	N.M.	N.M.	876	(3)	N.M.	N.M.
Other	2,266	992	5.1 - 16.0	N.M.	850	312	2.0 - 4.9	2 - 37
Total	$ 28,153	$ 10,509			$ 10,968	$ 4,328		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)		(%)	(in years)	(in millions)		(%)	(in years)
Production	$ 7,276	$ 4,004	2.7 - 3.8	30 - 120	$ 8,693	$ 3,879	2.6 - 3.9	20 - 120
Transmission	6,293	2,241	1.7 - 3.0	25 - 75	-	-	N.M	N.M
Distribution	10,280	3,043	3.2 - 4.1	10 - 75	-	-	N.M.	N.M.
CWIP	712	4	N.M.	N.M.	447	-	N.M.	N.M.
Other	2,258	922	5.4 - 16.4	N.M.	1,335	400	2.0 - 14.2	0 - 50
Total	$ 26,819	$ 10,214			$ 10,475	$ 4,279		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(%)	(in years)	(%)	(in years)
Production	2.5 - 3.8	30 - 120	2.3 - 3.9	35 - 120
Transmission	1.7 - 3.1	25 - 75	2.1 - 2.8	33 - 65
Distribution	3.3 - 4.2	10 - 75	N.M.	N.M.
Other	7.1 - 16.7	N.M.	2.0 - 15.6	2 - 50

N.M. = Not Meaningful

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 $0.66, $0.65 and $0.25 per ton in 2005, 2004 and 2003, respectively. In 2004, average amortization 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.

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 and Amortization. Actual removal costs incurred are debited to Accumulated Depreciation and Amortization. Any

excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization 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 obligation related to asset retirement. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

We have legal obligations for nuclear decommissioning costs for our Cook Plant, as well as for the retirement of certain ash ponds, wind farms and certain coal mining facilities. As of December 31, 2005 and 2004, our ARO liability was $946 million and $1,076 million, respectively, and included $731 million and $711 million for nuclear decommissioning of the Cook Plant.

As of December 31, 2005 and 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $870 million and $934 million, respectively, of which $870 million and $791 million relating to the Cook Plant are recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that were legally restricted for purposes of settling the nuclear decommissioning liabilities for STP was $143 million as of December 31, 2004. These assets, which were sold in 2005, are classified as Assets Held for Sale on our 2004 Consolidated Balance Sheet. Due to the sale, we are no longer responsible for the STP decommissioning liabilities.

We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

In the fourth quarter of 2005, we recorded $55 million of ARO in accordance with FIN 47. The liabilities are primarily related to the removal and disposal of asbestos in general buildings and generating plants (See "FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligation" (FIN 47)" and "Cumulative Effect of Accounting Changes" sections of Note 2).

The following is a reconciliation of the 2004 and 2005 aggregate carrying amounts of ARO:

	Amount (in millions)
ARO at January 1, 2004, Including Held for Sale	$ 899
Accretion Expense	64
Foreign Currency Translation	1
Liabilities Incurred	18
Liabilities Settled (a)	(57)
Revisions in Cash Flow Estimates	151
ARO at December 31, 2004, Including Held for Sale	1,076
Less ARO Held for Sale:	
South Texas Project (b)	(249)
ARO at December 31, 2004	$ 827
ARO at January 1, 2005, Including Held for Sale	$ 1,076
Accretion Expense	63
Liabilities Incurred (c)	76
Liabilities Settled	(4)
Revisions in Cash Flow Estimates	(9)
Less ARO Liability for:	
South Texas Project (b)	(256)
ARO at December 31, 2005 (d)	$ 946

(a) Liabilities Settled in 2004 predominantly include noncash reductions of ARO associated with the sales of the U.K. generation assets in July 2004 and AEP Coal Company, Inc. in March 2004.
(b) The ARO related to nuclear decommissioning costs for TCC's share of STP was transferred to the buyer in connection with the May 2005 sale (see "Dispositions" section of Note 10).
(c) Includes $55 million of ARO relating to the adoption of FIN 47.
(d) The current portion of our ARO, totaling $10 million, is included in Other in the Current Liabilities section of our 2005 Consolidated Balance Sheet.

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 $56 million, $37 million and $37 million in 2005, 2004 and 2003, respectively.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Temporary Cash Investments, 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 Temporary Cash Investments

Other Temporary Cash Investments include marketable securities that we intend to hold for less than one year and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115). We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Cash Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities reflected in Other Temporary Cash Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

The following is a summary of Other Temporary Cash Investments at December 31:

	2005				2004			
($ millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash (a)	$ 96	$ -	$ -	$ 96	$ 106	$ -	$ -	$ 106
Government Debt Securities	-	-	-	-	144	-	-	144
Corporate Equity Securities	2	29	-	31	25	-	-	25
Total Other Temporary Cash Investments	$ 98	$ 29	$ -	$ 127	$ 275	$ -	$ -	$ 275

(a) primarily represents amounts held for the payment of debt.

Proceeds from sales of current available-for-sale securities were $8,228 million, $670 million and $115 million in 2005, 2004 and 2003, respectively. Purchases of current available-for-sale securities were $8,075 million, $573 million and $314 million in 2005, 2004 and 2003, respectively. Gross realized gains from the sale of current available-for-sale securities were $47 million in 2005 and were not material in 2004 or 2003. Gross realized losses from the sale of current available-for-sale securities were not material in 2005, 2004 or 2003.

Inventory

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost. Gas inventory was carried at the lower of weighted average cost or market during 2004. Due to the sale of HPL in 2005, we no longer own any gas inventories.

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 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 APCo's 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 company's balance sheets (see "Sale of Receivables – AEP Credit" 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." 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 foreign currency translation balance of Accumulated Other Comprehensive Income (Loss) as of December 31, 2004 and 2005 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. In addition, in 2004 and 2005, we disposed of various non-U.S. equity method investments.

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Notes 4 and 6). Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia and Texas-ERCOT, respectively.

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 customers 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 capped, frozen or suspended for a period of years, fuel costs impact 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) authorized the billing of capped fuel rates on an interim basis until April 1, 2005 and subsequently extended these rates until June 30, 2007. In West Virginia, deferred fuel accounting for over- or under-recovery will begin July 1, 2006. 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 in our Consolidated Balance Sheets. 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 Consolidated Statements 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 the ERCOT portion of 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).

For power purchased under derivative contracts in our west zone where we are short capacity, 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 our Consolidated Statements of Operations on a net basis (see "Derivatives and Hedging" section of Note 14).

Domestic Gas Pipeline and Storage Activities

As a result of the sale of HPL in 2005, our domestic gas pipeline and storage activities have ceased. Prior to the sale of HPL, revenues were recognized from domestic gas pipeline and storage services when gas was delivered to contractual meter points or when services were provided, with the exception of certain physical forward gas purchase-and-sale contracts that were 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 our Consolidated Statements 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 our Consolidated Statements of Operations (see "Fair Value Hedging Strategies" section of 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 in a qualifying cash flow or fair value hedge relationship or as a normal purchase and sale. 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 our Consolidated Statements of Operations 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).

We participate in wholesale marketing and risk management activities in electricity and gas. For all contracts 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). 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 revenues on a net basis. Unrealized mark-to-market losses and gains are included in the balance sheets as Risk Management Asset or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge) or as hedges 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 our Consolidated Statements 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 derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income (Loss) and depending upon the specific nature of the risk being hedged, subsequently reclassified into Revenues or fuel expenses in our Consolidated Statements of Operations when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in our Consolidated Statements of Operations immediately (see "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" sections of 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 Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

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 are 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 amortized over the life of the 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 customers. 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 plants 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 Expense.

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. 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 all assets and liabilities, 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.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlement received at no cost from the Federal EPA. We follow the inventory model for all allowances. Allowances expected to be consumed within one year are reported in Fuel, Materials and Supplies. Allowances with expected consumption beyond one year are included in Other Noncurrent Assets-Other. These allowances are consumed in the production

of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Other Current Assets. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Utility Operations Revenue because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations.

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 IURC, the MPSC 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 permitted 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 net of 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 were included in Assets Held for Sale for amounts relating to STP in 2004. STP was sold in 2005. 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.

The following is a summary of nuclear trust fund investments at December 31:

	2005				2004			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)							
Cash	$ 21	$ -	$ -	$ 21	$ 22	$ -	$ -	$ 22
Debt Securities	691	7	(7)	691	691	10	(4)	697
Equity Securities	277	148	(3)	422	330	149	(2)	477
Total Nuclear Trust Fund Investments	989	155	(10)	1,134	1,043	159	(6)	1,196
Less: Investments Included in Assets Held for Sale	-	-	-	-	(107)	(37)	1	(143)
Spent Nuclear Fuel and Decommissioning Trusts	$ 989	$ 155	$ (10)	$ 1,134	$ 936	$ 122	$ (5)	$ 1,053

Proceeds from sales of nuclear trust fund investments were $706 million, $950 million and $621 million in 2005, 2004 and 2003, respectively. Purchases of nuclear trust fund investments were $761 million, $1,001 million and $708 million in 2005, 2004 and 2003, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $13 million, $13 million and $26 million in 2005, 2004 and 2003, respectively. Gross realized losses from the sales of nuclear trust fund investments were $17 million, $18 million and $6 million in 2005, 2004 and 2003, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2005 is as follows:

	Fair Value (In millions)
Within 1 year	$ 17
1 year – 5 years	298
5 years – 10 years	173
After 10 years	203
	$ 691

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,	
	2005	2004
Components	(In millions)	
Foreign Currency Translation Adjustments, Net of Tax	$ -	$ 6
Securities Available for Sale, Net of Tax	19	(1)
Cash Flow Hedges, Net of Tax	(27)	-
Minimum Pension Liability, Net of Tax	(19)	(349)
Total	$ (27)	$ (344)

Stock-Based Compensation Plans

At December 31, 2005, we have options outstanding under two stock-based employee compensation plans: The Amended and Restated American Electric Power System Long-Term Incentive Plan and the Central and South West Corporation Long-Term Incentive Plan (see Note 12). No stock option expense is reflected in our earnings, as AEP currently accounts for stock options under APB 25 and 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 is a nonqualified deferred compensation plan that permits directors to choose to defer up to 100 percent of their annual Board retainer into any of a variety of investment fund options, all with market based returns, including the AEP stock fund. The Stock Unit Accumulation Plan for Non-Employee Directors awards stock units to directors. Compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units.

The following table shows the effect on our Net Income and Earnings 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,		
	2005	2004	2003
	(in millions, except per share data)		
Net Income, as reported	$ 814	$ 1,089	$ 110
Add: Stock-based Compensation Expense Included in Reported Net Income, Net of Tax	22	15	2
Deduct: Stock-based Compensation Expense determined Under Fair Value Based Method for All Awards, Net of Tax	(22)	(18)	(7)
Pro Forma Net Income	$ 814	$ 1,086	$ 105
Earnings per Share:			
Basic – As Reported	$ 2.09	$ 2.75	$ 0.29
Basic – Pro Forma (a)	$ 2.09	$ 2.74	$ 0.27
Diluted – As Reported	$ 2.08	$ 2.75	$ 0.29
Diluted – Pro Forma (a)	$ 2.08	$ 2.74	$ 0.27

(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 calculation of our basic and diluted earnings (loss) per common share (EPS) is based on weighted average common shares shown in the table below:

	2005	2004	2003
		(in millions)	
Weighted Average Shares			
Basic Average Common Shares Outstanding	390	396	385
Assumed Conversion of Dilutive Stock Options and Awards (see Note 12)	1	-	-
Diluted Average Common Shares Outstanding	391	396	385

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share.

Options to purchase 0.5 million, 5.2 million and 5.6 million shares of common stock were outstanding at December 31, 2005, 2004 and 2003, 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 was no effect on diluted earnings per share in 2004 and 2003 related to our equity units (issued in 2002) because the market value of our common stock did not exceed $49.08 per share. The equity units were settled in 2005 (see "Equity Units and Remarketing of Senior Notes" section of Note 17).

Supplementary Information

Related Party Transactions	Year Ended December 31, 2005	2004	2003
		(in millions)	
AEP Consolidated Purchased Energy:			
Ohio Valley Electric Corporation (43.47% Owned)	$ 196	$ 161	$ 147
Sweeny Cogeneration Limited Partnership (50% Owned)	141	-	-
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)	20	14	9
Cash Flow Information			
Cash was paid (received) for:			
Interest (Net of Capitalized Amounts)	637	755	741
Income Taxes	439	(107)	163
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	63	123	45
Assumption (Disposition) of Liabilities Related to Acquisitions/Divestitures, Net	(18)	(67)	-
Noncash Construction Expenditures Included in Accounts Payable at December 31	253	116	92
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 480 MW located in Texas and an international power plant totaling 600 MW located in Mexico (see "Other Losses" section of Note 10). We sold our interest in the international power plant in February 2006.

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. At December 31, 2005 and 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 guaranteed $48 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.

On our Consolidated Balance Sheets, we reclassified $103 million of auction rate securities as of December 31, 2004 to Other Temporary Cash Investments from Cash and Cash Equivalents. At December 31, 2003, auction rate securities approximated $200 million.

On our Consolidated Statements of Operations, we reclassified the consumption of emission allowances and consumption of chemicals used in the generation of power from Maintenance and Other Operation to Fuel and Other Consumables Used for Electric Generation. These reclassifications totaled $110 million and $89 million for 2004 and 2003, respectively. We also reclassified the net gain or loss on the sales of emission allowances from Maintenance and Other Operation to Utility Operations Revenues. These reclassifications were not material for 2004 or 2003.

On our Consolidated Statements of Cash Flows, we have separately disclosed the operating, investing and financing portions of the cash flows attributable to our discontinued operations, which in prior periods were reported on a combined basis as a single amount. Additionally, we have included purchases and sales of auction rate securities and investments within our nuclear decommissioning and spent nuclear fuel trusts as a component of Investing Activities.

These revisions had no impact on our previously reported results of operations or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS 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 that we have determined relate to our operations.

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, "Accounting for Stock Issued to Employees." A cumulative effect of a change in accounting principle will be recorded for the effect of initially applying the statement.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required 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 is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. SFAS 154 was effective for us beginning January 1, 2006 and will be applied as necessary.

FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

We adopted FIN 47 during the fourth quarter of 2005. In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143, "Accounting for Asset Retirement Obligations." FIN 47 clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

We completed a review of our FIN 47 conditional ARO and concluded that we have legal liabilities for asbestos removal and disposal in general buildings and generating plants. In the fourth quarter of 2005, we recorded $55 million of conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to regulatory liability. Of the $55 million, we recorded an unfavorable cumulative effect of $26 million ($17 million, net of tax) for our nonregulated operations related to asbestos removal in the Utility Operations segment.

We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligations would only be recognized if and when we abandon or cease the use of specific easements.

Pro forma net income and earnings per share are not presented for the years ended December 31, 2004 and 2003 because the pro forma application of FIN 47 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during those periods.

As of December 31, 2004 and 2003, the pro forma liability for conditional ARO which has been calculated as if FIN 47 had been adopted at the beginning of each period was $52 million and $49 million, respectively.

See "Accounting for Asset Retirement Obligations (ARO)" section of Note 1 for further discussion.

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 cash flows in determining whether cash flows have been or will be eliminated and also what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We applied this issue to components we disposed or classified as held for sale, including the HPL disposition (see "Houston Pipe Line Company" section of Note 10).

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions," if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on our financial statements.

Future Accounting Changes

The FASB's 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, fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, earnings per share calculations, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its 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

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in our Consolidated Statements of Operations as Extraordinary Loss, Net of Tax (see "Texas True-Up Proceedings" section of Note 6).

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, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in a nonaffiliated utility's true-up order (see "Wholesale Capacity Auction True-up and Stranded Plant Cost" section of Note 6). These net adjustments were recorded as an extraordinary item of $121 million net of tax in accordance with SFAS 101 and are reflected in our Consolidated Statements of Operations as Extraordinary Loss, 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 net of tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in 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 2003, we recorded $242 million of net of tax income as a cumulative effect of accounting change for ARO in accordance with SFAS 143 ($249 million net of tax income in Utility Operations and $7 million net of tax loss in Investments - UK Operations segment).

In the fourth quarter of 2005, we recorded $17 million of net of tax loss as a cumulative effect of accounting change for ARO in accordance with FIN 47 in the Utility Operations segment.

See table below for details of the Cumulative Effect of Accounting Changes:

	Year Ended December 31,		
	2005	2004	2003
		(in millions)	
Accounting for Risk Management Contracts (EITF 02-3)	$ -	$ -	$ (49)(b)
Asset Retirement Obligations (SFAS 143)	-	-	242 (c)
Asset Retirement Obligations (FIN 47)	(17)(a)	-	-
Total	$ (17)	$ -	$ 193

(a) net of tax of $9 million
(b) net of tax of $19 million
(c) net of tax of $157 million

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2005 and 2004 by operating segment are:

	Utility Operations	Investments - Other	AEP Consolidated
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
Balance at January 1, 2005	$ 37.1	$ 38.8	$ 75.9
Impairment Losses	-	-	-
Balance at December 31, 2005	$ 37.1	$ 38.8	$ 75.9

In the fourth quarters of 2004 and 2005, 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 required.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are $23.9 million at December 31, 2005 and $29.7 million at December 31, 2004, net of accumulated amortization and are included in Other Noncurrent Assets on our Consolidated Balance Sheets. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

		December 31, 2005		December 31, 2004	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Patent	5	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Easements	10	2.2	0.7	2.2	0.5
Trade Name and Administration of Contracts	7	-	-	2.4	0.9
Purchased Technology	10	10.9	4.3	10.9	3.2
Advanced Royalties	10	29.4	13.6	29.4	10.6
Total		$ 42.6	$ 18.7	$ 45.0	$ 15.3

Amortization of intangible assets was $4 million, $4 million and $5 million for 2005, 2004 and 2003, respectively. Our estimated total amortization is $5 million per year for 2006 and 2007, $4 million per year for 2008 through 2010 and $2 million in 2011.

"Trade Name and Administration of Contracts" represents intangible assets related to HPL, which was sold in 2005 (see "Houston Pipeline Company" section of Note 10).

4. RATE MATTERS

APCo Virginia Environmental and Reliability Costs

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request included incurred and projected costs from July 1, 2004 through June 30, 2006 which relate to (i) environmental controls on coal-fired generators to meet the first phase of the final Clean Air Interstate Rule and Clean Air Mercury Rule issued in 2005, (ii) the Wyoming-Jacksons Ferry 765 kilovolt transmission line construction and (iii) other incremental T&D system reliability work.

In the filing, APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. In October 2005, the Virginia SCC denied APCo's request to place the proposed cost recovery surcharge in effect, on an interim basis subject to refund. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the public hearing in this case which began on February 27, 2006.

The Virginia SCC also ruled that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, the order permitted APCo to update its request to reflect additional actual costs and/or present additional evidence. Accordingly, in November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery of E&R costs to $21 million of actual incremental E&R costs incurred during the period July 1, 2004 through September 30, 2005.

Through December 31, 2005, APCo deferred $24 million of recorded E&R costs. It has not yet recorded $4 million of such costs which represent equity carrying costs that are not recognized until collected through regulated rates. In addition, APCo reversed $5 million of AFUDC/interest capitalized through December 31, 2005 related to incremental E&R capital investments that would have been duplicative of a portion of the deferred E&R carrying costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to include $20 million of incremental E&R costs in its electric rates. The staff also recommended the disallowance of the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that have been established as a regulatory asset as of December 31, 2005. We believe the staff's position is contrary to the Virginia SCC's October 2005 order, which denied APCo's request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incurred incremental E&R costs after the commission examines and approves such costs. If the Virginia SCC denies recovery of any of APCo's deferred E&R costs, the denial could adversely impact future results of operations and cash flows. Hearings began on February 27, 2006.

APCo and WPCo West Virginia Rate Case

In August 2005, APCo and WPCo collectively filed an application with the WVPSC seeking an initial increase in their retail rates of approximately $82 million. The initial increase requests approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism, which accounts for $72 million of the initial increase. The request also seeks approval to implement a system reliability tracker, which accounts for $10 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins transmission items.

In addition, APCo and WPCo requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining proposed supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively.

APCo has a regulatory liability of $52 million for pre-suspension over-recovered ENEC costs. APCo proposed to apply this $52 million, along with a carrying cost, to any future under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism.

In January 2006, APCo and WPCo submitted supplemental testimony addressing the Ceredo Generating Station acquisition (see "Acquisitions" section of Note 10) and certain revisions to their filing. The supplemental filing revised the initial requested increase of $82 million downward to $74 million. APCo revised the supplemental increases downward to $43 million, $8 million and $36 million, effective on January 1, 2007, 2008 and 2009, respectively.

In January 2006, APCo, WPCo and the WVPSC staff filed a joint motion requesting a change in the procedural schedule. The motion, as modified, requests that hearings begin in April 2006, new rates go into effect on July 28, 2006 and deferral accounting for over – or under – recovery of the ENEC costs begins July 1, 2006. In response to that motion, the WVPSC approved the proposed schedule including the commencement date for ENEC deferral accounting. At this time, we cannot predict the ultimate effect on future revenues, results of operations and cash flows of APCo's and WPCo's base rate increase proceeding in West Virginia.

I&M Indiana Settlement Agreement

In 2003, I&M's fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain parties to the negotiations reached a settlement. The IURC approved the settlement agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate. Total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis

effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor was adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at the Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate). If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total cumulative actual fuel costs (except during a Cook Plant outage of greater than 60 days) are less than the cap prices, the savings will be credited to customers over the next two fuel adjustment clause filings. Cumulative net fuel costs in excess of the capped prices cannot be recovered. If the Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

I&M experienced a cumulative under-recovery of fuel costs for the period March 2004 through December 2005 of $12 million. Since I&M expects that its cumulative fuel costs through the end of the fuel cap period will exceed the capped fuel rates, I&M recorded $9 million and $3 million of under-recoveries as fuel expense in 2005 and 2004, respectively. If future fuel costs per KWH through June 30, 2007 continue to exceed the caps, future results of operations and cash flows would be adversely affected.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC which seeks authorization effective January 1, 2006 to revise the book depreciation rates applicable to its electric utility plant in service. This petition is not a request for a change in customers' electric service rates. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Nuclear Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. If approved, the book depreciation expense reduction would increase earnings, but would not impact cash flows. Hearings are scheduled to begin in May 2006. When approved by the IURC, I&M will prospectively revise its book depreciation rates and, if appropriate, currently adjust its book depreciation expense to the approved effective date.

KPCo Rate Filing

In September 2005, KPCo filed a request with the Kentucky Public Service Commission (KPSC) to increase base rates by approximately $65 million to recover increasing costs. The major components of the rate increase included a return on common equity of 11.5% or $26 million, the impact of reduced through-and-out transmission revenues of $10 million, recovery of additional AEP Power Pool capacity costs of $9 million, additional reliability spending of $7 million and increased depreciation expense of $5 million. In February 2006, KPCo executed and submitted a settlement agreement to the KPSC for its approval. The major terms of the agreement are as follows: KPCo will receive a $41 million increase in revenues effective March 30, 2006, KPCo will retain its existing environmental surcharge tariff and KPCo will continue to include in the calculation of its annual depreciation expense the depreciation rates currently approved and utilized as a result of KPCo's 1991 rate case. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and for AFUDC purposes. The KPSC has not approved the settlement agreement and therefore, management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power and its Possible Impact on AEP East Companies

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 offered to collect those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs, future results of operations and cash flows would be adversely affected.

In the review of PSO's 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between and among AEP East companies and AEP West companies and specifically PSO was inconsistent with the FERC-approved Operating Agreement and SIA and that the AEP West companies should have been allocated greater margins. The parties objected to the inclusion of mark-to-market amounts in developing the allocation base. In addition, an intervenor recommended that $9 million of the $42 million related to the 2002 reallocation not be recovered from Oklahoma retail customers because that amount was not refunded by PSO's affiliated AEP West companies to their wholesale customers outside of Oklahoma.

The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002. In July 2005, the OCC staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East companies and AEP West companies. Their overall recommendations would result in an increase in off-system sales margins allocated to PSO and thus, a reduction in its recoverable fuel costs through December 2004 in a range of $38 million to $47 million.

In January 2006, the OCC staff and intervenors issued supplemental testimony proposing that the OCC offset the under-recovered fuel clause deferral inclusive of the $42 million with off-system sales margins of $27 million to $37 million through December 2004. The OCC staff also recommended a disallowance of $6 million. Hearings were held in early February 2006 to address the issues. PSO does not agree with the intervenors' and the OCC staff's recommendations and will defend vigorously its position.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. Intervenors appealed the ALJ ruling to the OCC. The OCC has not ruled on the intervenors' appeal or the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from deciding this same allocation issue in Texas. The Court agreed that the FERC had jurisdiction over the SIA and that the sole remedy is at the FERC.

If the OCC decides to provide for additional off-system sales margins, it could adversely affect future results of operations and cash flows. However, if the position taken by the federal court in Texas is applied to PSO's case, the OCC would be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins due to a lack of jurisdiction. The OCC or another party could file a complaint at the FERC which could ultimately be successful, and which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To-date there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings and future FERC proceedings, if any, on future results of operations, cash flows and financial condition.

In April 2005, the OCC heard arguments from intervenors that requested the OCC conduct a prudence review of PSO's fuel and purchased power practices for 2003. In June 2005, the OCC asked its staff to conduct that review. The OCC staff is scheduled to file its testimony in March 2006 and the hearings are scheduled for May 2006.

PSO 2005 Fuel Factor Filing

In November 2005, PSO submitted to the OCC staff an interim adjustment to PSO's annual fuel factors. PSO's new factors were based on increased natural gas and purchased power market prices, as well as past under-recovered fuel costs. PSO implemented the new fuel factors in its December 2005 billing. The new fuel factors are estimated to increase 2006 revenues by approximately $349 million. At December 31, 2005, PSO had a deferred under-recovered fuel balance of $109 million, which includes interest and the $42 million discussed above in "PSO Fuel

and Purchased Power and its Possible Impact on AEP East companies." This fuel factor adjustment will increase cash flows without impacting results of operations as any over or under-recovery of fuel cost will be deferred as a regulatory liability or regulatory asset.

PSO Rate Review

PSO was involved in an OCC staff-initiated base rate review, which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates by $41 million, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. The settlement provided for a $7 million annual base revenue reduction offset by a $6 million reduction in annual depreciation expense and recovery through fuel revenues of certain transmission expenses previously recovered in base rates. In addition, the settlement eliminated a $9 million annual merger savings rate reduction rider at the end of December 2005. The settlement also provided for recovery, over 24 months, of $9 million of deferred fuel costs associated with a renegotiated coal transportation contract and the continuation of a $12 million vegetation management rider, both of which are earnings neutral. Finally, the settlement stipulated that PSO may not file for a base rate increase before April 1, 2006. The OCC approved the stipulation in May 2005 and new base rates were implemented in June 2005.

PSO 2005 Vegetation Management Filing

In June 2005, PSO filed testimony to adjust its vegetation management rate rider from the OCC-approved $12 million to $27 million. In November 2005, the OCC issued a final order approving an increase to the cap on the PSO vegetation management rider to $24 million, which is in addition to the $6 million vegetation management expenses currently included in base rates. The final order also provided for the recovery of carrying and other costs associated with converting overhead distribution lines to underground lines. We do not anticipate any material effect on income for the incremental costs associated with the increased cap as the incremental costs will be deferred and expensed in the future when the rate rider revenues are recognized.

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported results of its review of SWEPCo's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. Management is unable to predict the outcome of this initial report on future revenues, results of operations, cash flows and financial condition.

SWEPCo Louisiana Fuel Issues

In November 2005, the Louisiana Public Service Commission (LPSC) amended an inquiry into the operation of the fuel adjustment clause recovery mechanisms of other Louisiana electric utilities to include SWEPCo. The inquiry was initiated to determine whether utilities had purchased fuel and power at the lowest possible price and whether suppliers offered competitive prices for fuel and purchased power during the period of January 1, 2005 through October 31, 2005.

In December 2005, the LPSC initiated a new audit of SWEPCo's historical fuel costs which will cover the years 2003 and 2004, pursuant to the LPSC's general order requiring biennial fuel reviews. Management cannot predict the outcome of these audits/reviews, but believes that SWEPCo's fuel and purchased power procurement practices were prudent and costs were properly incurred. If the LPSC disagrees and disallows fuel or purchased power costs incurred by SWEPCo, it would 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 LPSC's merger order also provided that SWEPCo's base rates were capped 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 SWEPCo's rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in

SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony was filed in January 2005 and subsequent deposition proceedings are in process. 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.

TCC Rate Case

In August 2005, the PUCT issued an order in a base rate proceeding initiated in 2003 by a Texas municipality. The order reduced TCC's annual base rates by $9 million. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. Tariffs were approved and the rate change was implemented effective September 6, 2005. TCC and other parties have appealed this proceeding to the Texas District Court. No schedule has been set for hearing the appeals. Management cannot predict the ultimate outcome of these appeals. Also, in the third quarter of 2005, TCC reclassified $126 million of asset removal costs from Accumulated Depreciation and Amortization to Regulatory Liabilities and Deferred Investment Tax Credits on our Consolidated Balance Sheets based on a depreciation study prepared by TCC and approved by the PUCT.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU, 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 of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court on the loss of load issue, but otherwise affirmed its decision. The amount of unaccounted-for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million. Our 2005 pretax earnings were adversely affected by $3 million because of this decision. In a decision on rehearing in February 2006, the Texas Court of Appeals no longer is directing on remand that the unaccounted for energy issue be reconsidered solely based on the existing record. The prior ruling would have prevented the PUCT from considering additional evidence on the $3 million adjustment. Management cannot predict the outcome of further appeals but a reversal of the favorable court of appeals decision regarding the loss of load issue would adversely impact results of operations and cash flows.

RTO Formation/Integration Costs

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs and carrying costs incurred to originally form a new RTO (the Alliance) and subsequently to integrate into an existing RTO (PJM). In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The FERC approved our application and in January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years consistent with a March 2005 requested rate recovery period discussed below. The total amortization related to such costs was $5 million in 2005. As of December 31, 2005 and 2004, the AEP East companies had $31 million and $33 million, respectively, of deferred unamortized RTO formation/integration costs. We did not record $5 million and $4 million of equity carrying costs in 2005 and 2004, respectively, which are not recognized until collected.

In March 2005, AEP and two other utilities jointly filed a request with the FERC to recover their deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. In May 2005, the FERC issued an order denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a compliance filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the compliance filing in May 2005. In June 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). In October 2005, the FERC granted our June 2005 rehearing request and set the following two issues for settlement discussions and, if necessary, for hearing: (i) whether the PJM OATT is unjust and unreasonable without PJM region-wide recovery of PJM-billed integration costs and (ii) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. Also, the FERC, in its order, dismissed the May 2005 compliance filing as moot. Settlement discussions are still underway, and a result that would collect a portion of the costs in other PJM zones is likely, though not yet assured.

In March 2005, we also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed below in the "AEP East Transmission Requirement and Rates" section). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of our deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs).

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM OATT to recover the amount of deferred RTO formation costs to be amortized, determined to be $2 million per year. The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In a December 2005 order, the Public Utilities Commission of Ohio (PUCO) approved recovery of the amortization of RTO Formation/Integration Costs through a Transmission Cost Recovery Rider (TCRR). In Kentucky and West Virginia, we have made filings to recover the amortization of these costs (see "KPCo Rate Filing" section of this Note). The Indiana service territory of I&M is subject to a rate freeze until June 2007, so recovery will be delayed until the freeze ends.

Until all the AEP East companies can adjust their retail rates to recover the amortization of both RTO related deferred costs, results of operations and cash flows will be adversely affected by the amortizations. The proposed FERC settlement would allow and establish a reasonable carrying charge for the deferred costs. If the FERC or any state regulatory authority was to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs, it would have an adverse impact on future results of operations and cash flows. If the FERC approves a carrying charge rate that is lower than the carrying charge recognized to date, it could have an adverse effect on future results of operations and cash flows.

Transmission Rate Proceedings at the FERC

FERC Order on Regional Through-and-out Rates and Mitigating SECA Revenue

In July 2003, the FERC issued an order directing PJM and 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).

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 elimination of the T&O charges for transactions between the two RTOs reduces the transmission service revenues collected by the RTOs and thereby, reduces the revenues received by transmission owners, including the AEP East companies, under the RTOs' revenue distribution protocols.

As a result of settlement negotiations in early 2004, the effective date of the SECA transition was delayed by the FERC. The delay was to give parties an opportunity to create a new regional rate regime. When the parties were unable to agree on a single regional rate proposal, the FERC ordered the two-year SECA transition period shortened to sixteen months, effective on December 1, 2004, continuing through March 31, 2006. The FERC has set SECA rate issues for hearing and indicated that the SECA rates are being recovered subject to refund or surcharge. The AEP East companies recognized net SECA revenues of $128 million in 2005. In addition, the AEP East companies recognized $11 million of net SECA revenues in December 2004. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. At this time, management is unable to determine the probable outcome of the FERC's SECA rate proceeding and its impact on future results of operations and cash flows.

AEP East Transmission Revenue Requirement and Rates

In the March 2005 FERC filing discussed in the "RTO Formation/Integration Costs" section above, we proposed a two-step increase in the revenue requirements and rates for transmission service, and certain ancillary services in the AEP zone of PJM. The customers receiving these services are the AEP East companies, municipal and cooperative wholesale entities, and retail choice customers with load delivery points in the AEP zone of PJM. In December 2005, the FERC approved an uncontested settlement allowing our wholesale transmission rates to increase in three steps: first, beginning November 1, 2005, second, beginning April 1, 2006 when the SECA revenues are expected to be eliminated and third, on the later of August 1, 2006 or the first day of the month following the date when our Wyoming-Jacksons Ferry transmission line enters service, currently expected to occur in June 2006.

PJM Regional Transmission Rate Proceeding

In a separate proceeding, at our urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC.

This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway. Under the Highway/Byway rate design proposed by AEP and AP, the cost of all transmission facilities in the PJM region operated at a voltage of 345 kilovolt (kV) or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's rate design which reflects the cost of the facilities in the corporate zone in which the transmission facilities are owned (License Plate Rate). The AEP/AP Highway/Byway design would result in incremental net revenues of approximately $125 million per year for the AEP East transmission-owning companies.

A competing Highway/Byway proposal filed by others would also produce net revenues to the AEP East transmission-owning companies, but at a much lower level. Both proposals are being challenged by a majority of transmission owners in the PJM region who favor continuation of the PJM License Plate Rate design. A group of LSEs has also made a proposal that would include 500 kV and higher existing facilities, and some facilities at lower voltages in the highway rate.

In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design. The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal. The case is scheduled for hearing in April 2006. AEP management cannot at this time estimate the outcome of the proceeding; however, adoption of any of the new proposals would have a positive effect on AEP revenues, compared to the License Plate Rates that will otherwise prevail beginning April 1, 2006 when the transitional SECA rates expire.

As of December 31, 2005, SECA transition rates have not fully compensated the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone will not be sufficient to replace the SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues will require cost recovery through retail rate proceedings. Rate requests are pending in Kentucky and West Virginia that address the reduction in FERC transmission revenues, (see "KPCo Rate Filing" section of this Note). In February 2006, CSPCo and OPCo filed with the PUCO to increase their transmission rates to reflect the loss of their share of SECA revenues. Management is unable to predict when and if the effect of the loss of transmission revenues will be recoverable on a timely basis in all of the AEP East state retail jurisdictions and from wholesale LSEs within the PJM region.

Future results of operations, cash flows and financial condition would be adversely affected if:

- the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or
- the newly approved AEP zonal transmission rates are not sufficient to replace the lost T&O/SECA revenues, or
- the FERC's review of our current SECA rates results in a rate reduction which is subject to refund, or
- any increase in the AEP East companies' transmission costs from the loss of transmission revenues are not fully recovered in retail rates on a timely basis, or
- the FERC does not approve a new regional rate within PJM.

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 applicant's minimum load. The FERC also initiated a rulemaking to consider whether the FERC's 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.

In a December 2004 order, the FERC affirmed our conclusions that we passed both market power screen tests in all areas except SPP. Because we did not pass the market share screen in SPP, the FERC initiated proceedings under Section 206 of the Federal Power Act in which we are rebuttably presumed to possess market power in SPP. In February 2005, although we continued to believe we did not possess market power in SPP, we filed a response and proposed tariff changes to address the FERC's 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.

In July 2005, the FERC accepted for filing the amended tariffs effective March 6, 2005 and set for hearing three aspects of the proposed tariffs. Two parties intervened in the proceeding protesting the proposed cost-based tariffs. In October 2005, all parties and the FERC staff entered into a settlement agreement adopting AEP's proposed tariffs with minor modifications to the rates in consideration of certain long-term power supply arrangements entered into between AEP and the intervenors. In November 2005, the FERC settlement judge issued a certification of uncontested settlement recommending that the settlement agreement be adopted with minor additional provisions to AEP's tariff to bring such tariff into compliance with existing FERC policy. The settlement certification was accepted by the FERC in January 2006.

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 from the FERC's and PJM's market power analysis cannot be determined. Since the cost caps apply only to wholesale loads within our control area inside SPP and these entities are not often in the market for additional power, we do not expect a significant adverse impact from the FERC's actions to-date.

Allocation Agreement between AEP East Companies and AEP West Companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. The current allocation methodology was established at the time of the AEP-CSW merger and, consistent with the terms of the SIA, in November 2005, we filed a proposed allocation methodology to be used in 2006 and beyond. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of the AEP West companies. Previously, the SIA allocation provided for a different method of sharing of all such margins between both AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from the one we proposed. We requested that the new methodology be effective on a prospective basis after the FERC's order. The impact on future results of operations and cash flows will depend upon the methodology approved by the FERC, the level of future margins by region and the status of cost recovery mechanisms by state. Our total trading and marketing margins are unaffected by the allocation methodology. However, because trading and marketing activities are not treated the same for ratemaking purposes in each state retail jurisdiction and the timing of inclusion of the margins in rates may differ, our results of operations and cash flows could be affected. Management is unable to predict the ultimate effect of this filing on our future results of operations and cash flows.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2005	December 31, 2004	Future Recovery/Refund Period
	(in millions)		
Regulatory Assets:			
Income Tax Related Regulatory Assets, Net	$ 785	$ 796	Various Periods (a)
Transition Regulatory Assets – Ohio and Virginia	306	407	Up to 5 Years (a)
Designated for Securitization - Texas	1,436	1,361	(b) (c)
Texas Wholesale Capacity Auction True-up	77	560	(c)
Unamortized Loss on Reacquired Debt	110	116	Up to 38 Years (d)
Cook Nuclear Plant Refueling Outage Levelization	23	44	(e)
Other	525	310	Various Periods (f)
Total Noncurrent Regulatory Assets	$ 3,262	$ 3,594	
Current Regulatory Asset – Under-Recovered Fuel Costs	$ 197	$ 7	
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	$ 1,437	$ 1,290	(g)
Deferred Investment Tax Credits	361	393	Up to 24 Years (a)
Excess ARO for Nuclear Decommissioning Liability	271	245	(h)
Over-recovery of Texas Fuel Costs	182	216	(c)
Deferred Over-recovered Fuel Costs	53	53	(a)
Texas Retail Clawback	75	75	(c)
Other	368	250	Various Periods (f)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,747	$ 2,522	

(a) Does not earn a return.
(b) Includes a carrying cost. The cost of the securitization bonds, when issued, would be recovered over a period of time 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 are included in TCC's and TNC's 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, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.
(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 Texas 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. See Note 6 for a discussion of our efforts to recover these regulatory assets, net of regulatory liabilities.

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 beginning in the third quarter of 2000:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	Rate reduction of $221 million over 6 years.
Indiana – I&M	Rate reduction 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.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreement in the remaining periods of the merger agreements, future results of operations and cash flows could be adversely affected.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of our twelve 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, Michigan, Virginia and Texas) in which the AEP electric utility companies operate. The following paragraphs discuss significant events related to industry restructuring in those states.

TEXAS RESTRUCTURING

The 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. The PUCT has begun studies to consider further delay of customer choice in the SPP area of Texas. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business operates in SPP.

The Texas Restructuring Legislation provides for True-up Proceedings to determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any 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 PUCT's 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 certain of the above true-up amounts.

In May 2005, TCC filed its True-Up Proceeding seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined that TCC's net true-up regulatory asset was $1.5 billion, which included carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules.

TCC adjusted its December 2005 books to reflect the PUCT's final order. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded in December 2005 as a pretax extraordinary loss. The difference between the requested amount of $2.4 billion, the approved amount of $1.5 billion and the recorded amount of $1.3 billion at December 31, 2005 is detailed in the table below:

	in millions
True-Up Proceeding Requested Amount	$ 2,406
Wholesale Capacity Auction True-up, including carrying costs	(572)
Commercial Unreasonableness Disallowance	(122)
Return on and of Stranded Costs Disallowance	(159)
Other	(78)
Amount Approved by the PUCT	1,475
Unrecognized but Recoverable Equity Carrying Costs and Other	(200)
Total Recorded Net True-up Regulatory Asset	$ 1,275

The requested $2.4 billion represents what TCC believes it should recover under its interpretation of the provisions of the Texas Restructuring Legislation. However, the $1.3 billion book amount reflects what management believes to be the probable recoverable net regulatory true-up asset at December 31, 2005, taking into account the PUCT's final order in TCC's True-up Proceeding exclusive of various items, principally recoverable but unrecognized equity carrying costs and other items.

Based on the PUCT-approved amount, and carrying costs through the proposed date of securitization, we anticipate requesting to securitize $1.8 billion, as discussed below in the "TCC Securitization Proceeding" section.

The Components of TCC's Net True-up Regulatory Asset as of December 31, 2005 and December 31, 2004 are:

	TCC	
	December 31, 2005	December 31, 2004
	(in millions)	
Stranded Generation Plant Costs	$ 969	$ 897
Net Generation-related Regulatory Asset	249	249
Excess Earnings	(49)	(10)
Net Stranded Generation Costs Before Carrying Costs	1,169	1,136
Carrying Costs on Stranded Generation Plant Costs	267	225
Net Stranded Generation Costs After Carrying Costs	1,436	1,361
Wholesale Capacity Auction True-up	61	483
Carrying Costs on Wholesale Capacity Auction True-up	16	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(177)	(212)
Net Other Recoverable True-up Amounts	(161)	287
Total Recorded Net True-up Regulatory Asset	$ 1,275	$ 1,648

The majority of the reduction to TCC's net true-up regulatory asset was comprised of two extraordinary adjustments, and the associated nonextraordinary debt carrying costs. The major adjustments were related to TCC's wholesale capacity auction true-up and its stranded plant cost from the sale of its generating plants. The PUCT found that TCC did not comply with the wholesale capacity auction requirements, which resulted in a book reduction of $422 million. Related to the sale of TCC's generation assets, the PUCT determined that TCC acted in a manner that was commercially unreasonable in large part because it failed to determine a minimum price at which it would reject bids for the sale of its generating plants. Based on that determination, TCC reduced its net true-up regulatory asset by $122 million. Other smaller adjustments totaling $7 million were reversed as an extraordinary item.

In addition, the PUCT determined that the purpose of the capacity auction true-up was to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the

duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded generation plant cost balance that it determined was included in the capacity auction true-up. Since TCC had previously reduced its book stranded cost regulatory asset by $238 million in 2004 related to the duplicate depreciation, TCC increased its book stranded generation plant cost by $206 million in December 2005. The reduction to debt carrying costs related to all of these adjustments totaled $71 million.

In 2003 and 2004, based upon orders received from the PUCT, TCC recorded provisions to its over-recovered fuel balance resulting in a $209 million over-recovery regulatory liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed as nonextraordinary in the fourth quarter of 2005.

In a future proceeding, certain adjustments for the future cost-of-money benefit of accumulated deferred federal income taxes may be deducted from the recoverable true-up asset, and transferred to a separate regulatory asset to be recovered in normal delivery rates outside of the securitization process which would affect the timing of cash recovery.

TCC believes that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT has issued in implementing that statute. TCC intends to seek rehearing of the PUCT's rulings. If the PUCT does not make significant changes in response to our request for reconsideration, we expect that TCC will challenge certain of the PUCT's rulings through appeals to Texas state and federal courts. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any requested rehearings or appeals.

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In TCC's final true-up order, the PUCT reduced net stranded generation costs by $51 million related to the present value of Accumulated Deferred Investment Tax Credits (ADITC) and by $10 million related to excess deferred federal income taxes (EDFIT) associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions. Also included in the final true-up order was language whereby the PUCT agreed to consider revisiting this issue if the Internal Revenue Service (IRS) ruled that the flow-through of ADITC and EDFIT constituted a normalization violation. Tax counsel has advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a final, nonappealable rate order. With the agreement in effect, as well as our ability to ultimately appeal the final true-up order, management does not believe a normalization violation has occurred. Although ADITC and EDFIT are recorded as a liability on TCC's books, such amounts are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table.

The IRS issued proposed regulations in March 2003 that would have liberalized the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS had not issued final regulations, TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. In December 2005, the IRS withdrew these previously proposed regulations and issued new proposed regulations. The new proposed regulations removed the retroactive election that allowed utilities, which were deregulated before March 4, 2003, to pass the benefits of ADITC and EDFIT back to ratepayers. The PUCT computation is premised on the withdrawn proposed regulations and may not be acceptable to the IRS under the new proposed regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of December 31, 2005 and also a loss of the ability to elect accelerated tax depreciation in the future. In light of the new proposed regulations, we are unable to predict how the IRS will ultimately rule on our private letter ruling request. However, prior precedent in this area would lead management to expect the IRS to rule that the PUCT approach of reducing the stranded cost recovery by the present value of its ADITC and EDFIT would, if ultimately imposed by a final, nonappealable order, constitute a normalization violation. Management intends to update the private letter ruling request for the new proposed regulations and issuance of the final order and will continue to work closely with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

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. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant costs, excess earnings have been applied to reduce transmission and distribution capital expenditures. Management believes excess earnings for TNC and SWEPCo are not true-up items. However, in January 2005, intervenors filed testimony in TNC's True-up Proceeding recommending that TNC's 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. In addition, intervenors also recommended that TNC's transmission and distribution rates should be reduced by a maximum amount of approximately $3 million on an annual basis related to excess earnings. The PUCT did not address the excess earnings in the final true-up order, and instead required that excess earnings be addressed in TNC's Competition Transition Charge (CTC) filing. TNC's CTC filing was made in August 2005. As noted below, this filing has been suspended until further notice.

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 reduced cash flows over the refund period. Through the end of 2004, TCC had refunded all but $10 million of its excess earnings liability. During 2005, TCC refunded an additional $9 million reducing its unrefunded excess earnings to $1 million. In July 2005, the PUCT approved a preliminary order in TCC's True-up Proceeding that instructed TCC to stop refunding the excess earnings and to offset the remaining balance, which was $1 million, against net stranded generation costs. In the final true-up order, the PUCT has utilized $1 million as a reduction to TCC's net stranded generation costs. However, prior to the final true-up order, in September 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings was unlawful under the Texas Restructuring Legislation. The decision stated that the excess earnings should have been treated as a reduction of stranded costs. As such, in September 2005, TCC recorded a regulatory asset of $56 million (including $7 million of interest) for the future recovery of the $49 million refunded to the REPs and a reduction to net stranded plant regulatory assets of $49 million, which also reduced the amount of carrying costs on TCC's books by $9 million. The PUCT filed a petition with the Texas Supreme Court to review the Texas Court of Appeals' decision. Management is unable to predict the ultimate outcome of these proceedings.

Wholesale Capacity Auction True-up and Stranded Plant Cost

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. 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 of $483 million in those years. TCC also recorded $126 million of carrying costs related to the wholesale capacity auction true-up, increasing the total asset to $609 million. As noted earlier, the PUCT ruled in the True-up Proceeding that TCC did not comply with the PUCT's rules regarding the auction of 15% of its Texas jurisdictional installed generation capacity. Based upon this ruling, TCC's capacity auction revenues were computed at higher nonauction prices and, as a result, TCC wrote off $422 million of its recorded regulatory asset and $110 million of related carrying costs. At December 31, 2005, TCC has a net true-up recoverable asset related to the wholesale capacity auction true-up of $77 million inclusive of remaining carrying costs.

In a nonaffiliated company's order, the PUCT also reduced that company's requested wholesale capacity auction true-up request. The PUCT determined that the nonaffiliated company had not met the PUCT's rules regarding the auction of 15% of its generation capacity because it failed to sell 15% of its generating capacity. That utility appealed the PUCT's decision to the Texas District Court. The District Court found that the PUCT erred by disallowing a significant portion of that utility's wholesale capacity auction true-up request. Although the facts regarding the nonaffiliated company's wholesale capacity auction true-up request and TCC's wholesale capacity auction true-up request are not exactly the same, management believes the District Court decision is a positive

outcome and will prove to be beneficial to TCC's future claim that it is entitled to a significant portion, if not all, of TCC's requested amount.

In addition, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT then determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded plant cost balance that it determined was included in the capacity auction true-up. Since TCC had reduced its booked stranded cost regulatory asset by $238 million in December 2004 related to the duplicate depreciation, TCC increased its stranded plant cost regulatory asset by $206 million effectively adjusting its books to recognize the significantly lower $32 million net disallowance.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to their 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. At December 31, 2005, TCC's recorded retail clawback regulatory liability was $61 million and TNC's was $14 million. TCC recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $61 million, for the retail clawback liability. TNC received payment of $14 million from its nonaffiliated PTB REP in 2005, but has not refunded this money to its customers as of December 31, 2005. TNC's CTC proceeding, the proceeding that will determine the refund methodology, has been suspended. TCC received payment from its nonaffiliated REP in February 2006.

Fuel Balance Recoveries

In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred fuel balance for inclusion in their True-up Proceedings. The PUCT issued final orders in each of these proceedings that resulted in significant disallowances for both companies. Based upon these orders, TCC increased its over-recovered fuel balance by a total of $140 million, which resulted in a $209 million over-recovery liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed in the fourth quarter of 2005. TNC's under-recovered balance was adjusted by a total of $31 million. After the adjustments, TNC's under-recovered balance became an over-recovery of $5 million. Both TCC and TNC have challenged the PUCT's rulings regarding a number of issues in the fuel orders in federal and state court. Intervenors have also challenged certain rulings in the PUCT fuel order in state court.

In September 2005, the Texas District Court in Travis County issued a ruling which upheld the PUCT's decisions in the TNC proceeding. TNC and other parties have filed notice of appeal of that decision. TCC has not received a ruling from the Texas District Court regarding its appeal.

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the favorable federal TNC ruling is applicable to its appeal. The impact of the court order could result in reductions to the over-recovered fuel balances of $8 million for TNC and $14 million for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the Federal Court system, it could file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT is unsuccessful in its federal court appeal, TCC and TNC can reverse their provisions. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies. This is because the ruling may result in a reallocation of off-system sales margins between AEP East companies and

AEP West companies. If that occurs, the AEP West companies would receive additional off-system sales margins from the AEP East companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the additional payments from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

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.

In June 2004, the Texas Supreme Court determined that carrying costs 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 a nonaffiliated company's true-up order, the PUCT addressed the Supreme Court's remand decision and specified the manner in which carrying costs should be calculated. Based on this order, TCC first recorded carrying costs in 2004 and continued to accrue carrying costs in 2005. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. As a result, TCC recorded a $27 million reduction in its carrying costs in the first quarter of 2005 and reduced the amount of carrying costs accrued for the remainder of 2005. The PUCT indicated that it will address this retrospective ADFIT cost of money benefit in TCC's securitization proceeding.

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax cost of capital rate from its unbundled cost of service rate proceeding. The embedded debt component of the carrying cost rate is 8.12%. Based on the final order in TCC's True-up Proceeding, TCC reversed, in December 2005, $71 million of carrying costs, resulting in a net $19 million reduction in total carrying costs for 2005. Through December 2005, TCC recorded $283 million of carrying costs ($267 million on stranded generation plant costs and $16 million on wholesale capacity auction true-up). The remaining equity component of $153 million will be recognized in income as collected. TCC will continue to accrue a carrying cost.

In January 2006, the PUCT approved publication of a proposed rule that would reduce the 11.79% rate of return on nonsecuritized true-up amounts to the most recently approved weighted average cost of debt, which would be 5.70% for TCC. The effective date of the change is proposed to be (i) January 1, 2002 for utilities that have not received a final true-up order or (ii) the date the rule is adopted for utilities that have received a final order. There will be a 45-day comment period regarding the rule. TCC received a final order (which is subject to rehearing) in the True-up Proceeding in February 2006. AEP will assert in comments filed in the rulemaking proceeding that the rule change should not have retroactive application. However, TCC cannot predict if the rule will be adopted, or if it will be adopted in its present prospective form for utilities that have received their final true-up order.

The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until a final order is issued in TCC's True-up Proceeding. At that time, carrying costs accrue on the deferred fuel. For the retail clawback, carrying costs accrue when a final order is issued in TCC's True-up Proceeding.

TCC Securitization Proceeding

TCC anticipates filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which TCC anticipates will be negative, and as such will reduce rates to customers through a negative competition transition charge. The estimated amount for rate reduction to customers, including carrying costs

through August 31, 2006, is approximately $475 million. TCC will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an ADFIT benefit related to TCC's stranded generation cost, and the positive wholesale capacity auction true-up balance. TCC anticipates making a filing to implement its CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

	in millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	**$ 1,275**
Unrecognized but Recoverable Equity Carrying Costs and Other	200
Estimated January 2006 – August 2006 Carrying Costs	144
Securitization Issuance Costs	24
Net Other Recoverable True-up Amounts (a)	161
Estimated Securitization Request	**$ 1,804**

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

The final order did not address the allocation of stranded costs to TCC's wholesale jurisdiction which will be addressed in TCC's securitization proceeding. TCC estimates the amount allocated to wholesale to be less than $1 million. However, TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize.

TCC True-up Proceeding Summary

We believe that our recorded net true-up regulatory asset at December 31, 2005 of $1.3 billion accurately reflects the PUCT's final order in TCC's True-up Proceeding. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the net transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no additional impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding. If we determine in future securitization and CTC proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

The Components of TNC's True-up Regulatory Liability as of December 31, 2005 and December 31, 2004 are:

	TNC	
	December 31, 2005	December 31, 2004
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	**$ (19)**	**$ (18)**

TNC completed its True-up Proceeding in 2005 with the PUCT issuing a final order in May 2005. Based upon that final order, TNC adjusted its true-up regulatory liability. TNC filed a CTC proceeding in August 2005 to establish a rate to refund the net true-up regulatory liability. That filing has been suspended until the ruling from TNC's appeal to federal court regarding its final fuel reconciliation is fully resolved. This federal court ruling is discussed above. TNC accrues interest expense on the unrefunded balance and will continue accruing interest expense until the balance is fully refunded.

OHIO RESTRUCTURING

The Ohio Electric Restructuring Act of 1999 (Restructuring Act) provided for a Market Development Period (MDP) during which retail customers could 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 ended on December 31, 2005. 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. As of December 31, 2005, none of OPCo's customers have elected to choose an alternate power supplier and only a modest number of CSPCo's small commercial customers have switched suppliers.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. In February 2004, CSPCo and OPCo (the Ohio companies) filed Rate Stabilization Plans (RSP) 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 AEP's generation resources that serve Ohio customers.

In January 2005, the PUCO approved the RSP for the Ohio companies. The approved plans provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues for specified costs. CSPCo's cost recovery under the Power Acquisition Rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding (see "Acquisitions" section of Note 10) will diminish CSPCo's potential for the additional annual 4% generation rate increases in 2006 by approximately one-half and to a lesser extent in 2007 and 2008. The plans also provide that the Ohio companies can recover in 2006, 2007 and 2008 environmental carrying costs and PJM-related administrative costs and congestion costs net of firm transmission rights (FTR) revenue from 2004 and 2005 related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $9 million for CSPCo and $47 million for OPCo in 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo related to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding its approval of the RSP. In March 2005, the PUCO denied all applications for rehearing. In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSP and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. If the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo's and OPCo's future earnings will be adversely affected. In a nonaffiliated utility's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In addition, if the RSP order were determined on appeal to be illegal under the Restructuring Act, it would have an adverse effect on results of operations, cash flows and possibly financial condition. Although we believe that the RSP plan is legal and we intend to defend vigorously the PUCO's order, we cannot predict the ultimate outcome of the pending litigation.

In July 2005, CSPCo and OPCo each filed applications with the PUCO to decrease the transmission rates contained in their retail electric rates in order to reflect the FERC-approved OATT rate. Those applications were supplemented in December 2005 to update the proposed transmission rates to reflect the rates filed as part of a settlement agreement with the FERC (see "RTO Formation/Integration Costs" section of Note 4). As a result, annual transmission rates would be reduced by approximately $25 million. In accordance with the Restructuring Act, the Ohio companies also proposed to increase their distribution rates to fully offset the resulting decrease in

their transmission rates. The PUCO approved these applications on December 28, 2005 and the new offsetting transmission and distribution rates became effective on that date. Under the terms of the PUCO's order in the RSP, the modified distribution rates in effect on December 31, 2005 are frozen though December 31, 2008 with certain exceptions, including governmentally-imposed changes resulting in increased distribution costs, changes in taxes or for major storm damage service restoration.

In September 2005, the Ohio companies filed with the PUCO to recover through a Transmission Cost Recovery Rider, beginning January 1, 2006, approximately $5 million for CSPCo and $7 million for OPCo of projected 2006 annual net costs incurred as a result of joining PJM. In addition, the Ohio companies requested to practice over/under-recovery deferral accounting for any differences between the revenues collected starting January 1, 2006 and the actual PJM costs incurred. In December 2005, the PUCO issued an order approving the rider components.

In February 2006, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective the later of August 2006 or the first day of the month in which the Wyoming-Jacksons Ferry transmission line enters service in order to reflect their share of costs for that new line. We anticipate that, if approved, the filing will result in increased revenues for CSPCo and OPCo of $32 million and $42 million, respectively, in 2006 increasing in 2007 to $46 million and $59 million for CSPCo and OPCo, respectively. This filing follows the settlement of our March 2005 filing with the FERC requesting increased OATT rates in which we received a three-step increase (see "FERC Order on Regional Through-and-out Rates and Mitigating SECA Revenue" section of Note 4).

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, 2005, we incurred $90 million of such costs and, accordingly, we deferred $43 million of such costs for probable future recovery in distribution rates. We have not yet recorded $7 million of equity carrying costs which are not recognized until collected. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio 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.

MICHIGAN RESTRUCTURING

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date, the rates on I&M's 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&M's total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2005, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2005 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

VIRGINIA RESTRUCTURING

In April 2004, the Governor of Virginia signed legislation that extended 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. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the revised restructuring law, APCo is deferring incremental environmental generation costs for future recovery.

ARKANSAS RESTRUCTURING

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's 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 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 2001 through 2003, the West Virginia Legislature failed to enact the required tax legislation and the WVPSC closed its dockets. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCo's outside counsel advised that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's West Virginia generation. As a result, in March 2003, management concluded that deregulation of APCo's 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 NSR requirements 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. A bench trial on the liability issues was held during July 2005. Briefing has concluded but no decision has been issued.

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 component or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. 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.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer, and Stuart Stations. Similar cases have been filed against other nonaffiliated utilities.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability we might have 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, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In July 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 several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

In July 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. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

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

In July 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, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts associated with global warming, and sought 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. In September 2005, the lawsuits were dismissed. The trial court's dismissal has been appealed to the Second Circuit Court of Appeals and briefing continues. We believe the actions are without merit and intend to defend vigorously against the claims.

Ontario Litigation

In June 2005, we and several nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted NO_X, SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

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 treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our

generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2005, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites. There are seven 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. 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. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

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.

NUCLEAR

Nuclear Plant

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant. The operation of a nuclear facility also 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 is 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, which must be carried for each licensed reactor, 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 $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. 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 is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $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 utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

In 2005, the Price-Anderson Act was extended by amendment though December 31, 2025.

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 the Cook Plant is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $236 million for fuel consumed prior to April 7, 1983 at the 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, 2005, funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $264 million are in external trust funds.

SNF Litigation

The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. 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. The DOE failed to begin accepting SNF by the January 1998 deadline in the law. DOE continues to fail 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, we, 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 nuclear waste will not be ready until at least 2010. In 1998, we 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 January 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability.

The case was tried in March 2004 on the issue of damages owed to us by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against us and denied damages, ruling that pre-breach and post-breach damages are not recoverable in a partial breach case. In July 2004, we appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. In September 2005, the U.S. Court of Appeals ruled that the trial court erred in ruling that pre-breach damages in a partial breach case are per se not recoverable, but denied our pre-breach damages on the facts alleged. The Court of Appeals also ruled that the trial court did not err in determining that post-breach damages are not recoverable in a partial breach case, but determined that we may recover our post-breach damages in later suits as the costs are incurred.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. After expiration of the licenses, the 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 the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions. 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 was $27 million in 2005, 2004 and 2003.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2005 and 2004 and $12 million in 2003 related to special regulatory commission approved funding for decommissioning of the Cook Plant. At December 31, 2005, the total decommissioning trust fund balance for Cook Plant was $870 million. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs for the Cook Plant including interest, unrealized gains and losses and expenses of the trust funds, increase or decrease the recorded liability.

Estimates from the decommissioning study 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 will work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. 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.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. Aggregate construction expenditures for 2006 for consolidated operations are estimated to be $3.7 billion. 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 2021. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

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 and costs of replacement power in the event of a nuclear incident at the Cook Plant. 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.

Power Generation Facility and TEM Litigation

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. The initial term of our lease with Juniper (Juniper Lease) 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. The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability. 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 Lease's 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 us should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow as described below. If the Juniper 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 Juniper's 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 Juniper's acquisition costs, we may be required to make a payment (not to exceed $415 million) to Juniper for the excess of Juniper's 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 Juniper's 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.

Juniper's acquisition costs for the Facility totaled 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 Juniper's 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 $33 million represent future minimum lease payments to Juniper during the initial term. The majority of the payment is calculated using the indexed LIBOR rate (4.53% at December 31, 2005). Annual sublease payments received from Dow are approximately $36 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 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) 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.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In April 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 was terminated and (iii) would be pursuing against TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM had breached the contract and awarded us damages of $123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (i) award a termination payment to us under the terms of the PPA; (ii) grant our attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted our motion for reconsideration concerning TEM's parent guaranty and increased our judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found to be unenforceable by the court ultimately deciding the case, 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.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to properly explain how the June 15, 2000 merger of AEP with CSW met the requirements of the PUHCA and sent the case back to the SEC for further review. Upon repeal of the PUHCA on February 8, 2006, we received a letter from the SEC, which dismissed the proceeding challenging our merger with CSW.

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 Enron's 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 Enron's bankruptcy.

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 billion cubic feet (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 (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 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 Texas state court 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 BOA's 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 Enron's 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 BOA's 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 objected to the Magistrate Judge's decision. In April 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements and have filed an adversary proceeding contesting Enron's right to reject these agreements.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's 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. 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. Enron's claim sought to unwind the effects of the transaction. In December 2005, the parties reached a settlement resulting in a pretax cost of approximately $46 million.

Enron Bankruptcy – Summary – The amount expensed in current and 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, the settlement agreement and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of the remaining 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, three putative class action lawsuits were filed against AEP, certain executives and AEP's 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 filed a Motion to Strike Class Action Allegations and to Stay Further Merits Discovery Pending Resolution of Class Certification Issues. 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. A number of similar cases were filed in California. In addition, a number of other 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. Several of these cases had been transferred to the United States District Court for the District of Nevada but subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine and in December 2005, the judge dismissed two additional cases on the same ground. Plaintiffs in these cases have appealed the decisions. We will continue to defend vigorously 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. These cases have been consolidated. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied. In October 2005, the court granted the plaintiffs motion for class certification. The defendants have filed a petition for leave to appeal this decision. We intend to continue 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 us and four of our subsidiaries, ERCOT and a number of nonaffiliated energy companies. The action alleged 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 alleged that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced TCE into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleged over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. The Court dismissed all claims against the AEP companies. TCE appealed the trial court's decision and the appellate court affirmed the lower court's decision. TCE filed a Petition for Writ of Certiorari with the United States Supreme Court, which was denied in January 2006. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit against the same defendants and others. In December 2005, the federal court dismissed the plaintiffs' federal claims with prejudice and dismissed their state law claims without prejudice. After that decision, we settled all claims with plaintiffs in a settlement, subject to a confidentiality clause, and without material impact on results of operations or financial condition.

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. 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 did 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 ended their investigations and the CFTC litigation filed in September 2003 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. There was no impact on 2005 results of operations as a result of these investigations and settlements.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us. 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. We claimed that BOM owed us at least $41 million related to previously recorded receivables on which we held approximately $20 million of credit collateral. In September 2005, we reached a settlement with BOM, subject to a confidentiality clause, without material impact on results of operations or financial condition.

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 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 ALJ's 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 in accordance with FIN 45 "Guarantor's 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 (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At December 31, 2005, the maximum future payments for all the LOCs are approximately $130 million with maturities ranging from February 2006 to March 2007. $58 million of this relates to our international power plant equity investment, which was sold in February 2006.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $53 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provided 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, 2005, 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. After consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which 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 2005, 2004 and 2003, we entered into several sale agreements. The status of certain sales agreements is discussed in the "Dispositions" section of Note 10. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.2 billion, $1 billion of which expired in January 2006. There are no material liabilities recorded for any indemnifications.

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, 2005, the maximum potential loss for these lease agreements was

approximately $54 million ($35 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. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As result of a 2005 company-wide staffing and budget review, approximately 500 positions were identified for elimination. Pretax severance benefits expense of $28 million was recorded (primarily in Maintenance and Other Operation) in 2005. Approximately 95% of the expense was within the Utility Operations segment. The following table shows the total 2005 expense recorded and the remaining accrual (reflected primarily in Current Liabilities – Other) as of December 31, 2005:

	Amount (in millions)
Total Expense	$ 28
Less: Total Payments	16
Remaining Accrual at December 31, 2005	$ 12

The remaining accrual is expected to be settled by the end of the second quarter of 2006, when severance efforts are scheduled to cease.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND OTHER LOSSES

ACQUISITIONS

2005

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company (Utility Operations segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, we agreed to terms of a transaction, which includes the transfer of Monongahela Power's Ohio customer base and the assets, at net book value, that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of its customers over approximately 5 years. Also included in the transaction was a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station (Utility Operations segment)

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of a 505 MW plant located near Ceredo, West Virginia. This transaction was completed in December 2005 for $100 million.

DISPOSITIONS

2005

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (Investments – Other segment)

In November 2000, AEP made its initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. AEP Investments, Inc. (AEP Investments) sold approximately 2.1 million shares (71% of its investment in ICE) and recognized a $47 million pretax gain ($30 million, net of tax). AEP Investments' remaining fair value investment in ICE securities at December 31, 2005, classified as available for sale, is $31 million and AEP Investments is restricted from selling the remaining 0.9 million shares until May 2006.

Houston Pipe Line Company (HPL) (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 management's decision not to operate HPL as a major trading hub. The cash flow analysis used management's 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 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 on our Consolidated Statements of Operations.

In January 2005, we sold a 98% controlling interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We retained a 2% ownership interest in HPL at that time and provided certain transitional administrative services to the buyer. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we have recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $379 million as of December 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Consolidated Balance Sheets. The deferred gain was decreased in November 2005 by a $3 million payment related to purchase price true-up adjustments as defined in the contract. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a resulting inability to use the cushion gas (see "Enron Bankruptcy – Right to use of cushion gas agreements" section of Note 7). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008 and the cushion gas arrangement. In addition, the Company continues to hold forward gas contracts not sold with the gas pipeline and storage assets.

On November 14, 2005, we exercised a put option which allowed us to sell our remaining 2% interest to the buyer for approximately $17 million, which increased the deferred gain by approximately $8 million.

Pacific Hydro Limited (Investments – Other segment)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $88 million. The sale was contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. The sale was consummated in July 2005 and we recognized a pretax gain of $56 million. This gain is classified as Gain on Disposition of Equity Investments, Net on our 2005 Consolidated Statement of Operations.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement.

There had been an ongoing dispute between AEP and Centrica related to the ESM calculation. In March 2005, AEP and Centrica entered into a series of agreements resulting in the resolution of open issues related to the sale and the disputed ESM payments for 2003 and 2004. Also in March 2005, we received payments related to the ESM payments of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005, which is reflected in Gain/Loss on Disposition of Assets, Net on our accompanying Consolidated Statements of Operations. The ESM payments are contingent on Centrica's future operating results and are capped at $70 million and $20 million for 2005 and 2006, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 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 TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on our results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System which included all of the generation facilities owned by our Registrant Subsidiaries. TCC's assets and liabilities related to STP were classified as Assets Held for Sale and Liabilities Held for Sale, respectively, on our Consolidated Balance Sheet as of December 31, 2004.

<u>2004</u>

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. See "Discontinued Operations" section 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 related to the impairment of goodwill and $5 million related to other charges. In January 2004, a decision was made to sell LIG's pipeline and processing assets separate from LIG's 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 results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations on our Consolidated Statements of Operations. See "Discontinued Operations" section 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 results of operations and loss on sale of JISH are classified as Discontinued Operations on our Consolidated Statements of Operations. See "Discontinued Operations" section 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 was 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.

In 2003, as a result of management's 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 are included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

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.

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-MW, gas-fired, combined cycle, cogeneration plant in Brush, Colorado and a 50% interest in Thermo, a 272-MW, gas-fired, combined cycle, cogeneration plant located in Ft. Lupton, Colorado. Our two Florida investments included a 46.25% interest in Mulberry, a 120-MW, gas-fired, combined cycle, cogeneration plant located in Bartow, Florida and a 50% interest in Orange, a 103-MW, 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 2004 Consolidated Statement of Operations.

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 on our 2004 Consolidated Statement 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.

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).

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 million, 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 $156 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 management's 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 on our 2003 Consolidated Statement of Operations.

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 (Fiddler's 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 matured or were settled with the applicable counterparties during 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" section 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 ERCOT's 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 an 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 ERCOT's 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 $34 million was recorded during the third quarter of 2002. 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 in 2002.

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 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. Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in Regulatory Assets in 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in Regulatory Assets.

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 Held for Sale on our Consolidated Balance Sheets. In accordance with the Texas Restructuring Legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which was expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding (see "Texas Restructuring" section of Note 6).

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 2004 results of operations.

The remaining generation assets and liabilities of TCC (TCC's interest in the Oklaunion plant) are classified as Assets Held for Sale and Liabilities 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-MW, 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.

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). The gain reflects improved conditions in the U.K. power market. This gain was recorded to Gain on Disposition of Equity Investments, Net on our 2004 Consolidated Statement of Operations.

Excess Real Estate (Investments – Other segment)

In the fourth quarter of 2002, we began marketing 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 the second quarter of 2003 and an estimated 2002 pretax loss on disposal of $16 million was recorded, based on the option sale price. We recorded an additional pretax impairment of $6 million in Maintenance and Other Operation on our 2003 Consolidated Statement of Operations based on market data. The original prospective buyer did not complete their purchase of the building by the end of 2003.

In June 2004, we entered into negotiations to sell the Dallas office building. 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.

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

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) 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 contractual 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, net of tax), as no further service obligations existed for MESC. This gain was recorded in Gain/Loss on Disposition of Assets, Net on 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 2003 based upon final terms of the sale agreement. We had provided for a pretax charge of $7 million in 2002 based on an estimated sales price ($3 million asset impairment charge and $4 million lease prepayment penalty). 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.

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 during the fourth quarter of 2002.

We completed the sale of Eastex during 2003 and the effect of the sale on 2003 results of operations was not significant. The results of operations of Eastex were 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.

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 Held for Sale and Liabilities 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 2005, 2004 and 2003. Results of operations of these businesses have been classified as shown in the following table (in millions):

	SEE-BOARD (a)	CitiPower	Eastex	Pushan Power Plant	LIG (b)(c)	U.K. Generation (c)	Total
2005 Revenue	$ 13	$ -	$ -	$ -	$ -	$ (7)	$ 6
2005 Pretax Income (Loss)	10	-	-	-	-	(13)	(3)
2005 Earnings (Loss), Net of Tax	24	-	-	-	5	(2)(d)	27
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(e)	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)(f)	(605)

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.
(c) 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.
(d) Earnings per share related to the UK Operations was $(0.01).
(e) Earnings per share related to the UK Operations was $0.23.
(f) Earnings per share related to the UK Operations was $(1.32).

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2005, AEP recorded pretax impairments of assets totaling $46 million ($39 million related to assets impairments and $7 million related to Investment Value Losses) that reflected our decision to retire two generation units and our decision to exit noncore businesses and other factors.

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 on the Consolidated Statement 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 on the 2003 Consolidated Statement 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.

The categories of impairments and gains on dispositions include:

	2005	2004	2003
		(in millions)	
Asset Impairments and Other Related Charges (Pretax)			
AEP Coal, Inc.	$ -	$ -	$ 67
HPL and Other	-	-	315
Power Generation Facility	-	-	258
Blackhawk Coal Company	-	-	10
CSPCo's Conesville Units 1 and 2	39	-	-
Total	$ 39	$ -	$ 650
Investment Value Losses (Pretax)			
Independent Power Producers	$ -	$ (2)	$ (70)
Bajio	(7)	(13)	-
Total	$ (7)	$ (15)	$ (70)
Gain on Disposition of Equity Investments, Net			
Independent Power Producers	$ -	$ 105	$ -
South Coast Power Investment	-	48	-
Pacific Hydro Limited	56	-	-
Total	$ 56	$ 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)
Louisiana Intrastate Gas (a)	-	-	(99)
Total (b)	$ -	$ -	$ (474)
Operations:			
U.K. Generation Plants	$ (2)	$ 91	$ (133)
Louisiana Intrastate Gas (a)	5	(12)	8
CitiPower	-	-	(13)
Eastex	-	-	(14)
SEEBOARD	24	(2)	16
Pushan	-	6	5
Total	$ 27	$ 83	$ (131)
Total Discontinued Operations	$ 27	$ 83	$ (605)

(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 TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. By 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 TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were 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 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 requested that the court declare the co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of the unrelated party on October 10, 2005. TCC and the other nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. A decision by the Appeals Court is expected during the first half of 2006. 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. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, on our Consolidated Balance Sheets at December 31, 2005 and 2004. The plant does not meet the "component-of-an-

entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries.

The Assets Held for Sale and Liabilities Held for Sale at December 31, 2005 and 2004 are as follows:

Texas Plants	December 31, 2005	December 31, 2004
	(in millions)	
Assets:		
Other Current Assets	$ 1	$ 24
Property, Plant and Equipment, Net	43	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale	$ 44	$ 628
Liabilities:		
Regulatory Liabilities	$ -	$ 1
Asset Retirement Obligations	-	249
Total Liabilities Held for Sale	$ -	$ 250

OTHER LOSSES

2005

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following management's extensive review of the commercial viability of AEP's generation fleet, management committed to a plan to retire CSPCo's Conesville units 1 and 2 before the end of their previously estimated useful lives. As a result, Conesville units 1 and 2 were considered retired as of the third quarter of 2005.

A pretax charge of approximately $39 million was recognized in 2005 related to our decision to retire the units. The impairment amount is classified as Asset Impairments and Other Related Charges in our 2005 Consolidated Statement of Operations.

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-MW power plant in Mexico. A pretax other-than-temporary impairment charge of $13 million was recognized in December 2004 based on an indicative bid, which did not result in a sale.

In September 2005, a pretax other-than-temporary impairment charge of approximately $7 million was recognized based on an indicative offer received in September 2005. Both the 2005 and 2004 impairment amounts are classified as Investment Value Losses on our Consolidated Statements of Operations. The sale was completed in February 2006 without significant effect on our 2006 results of operations.

2003

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 operation 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 management's 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 on our 2003 Consolidated Statement of Operations.

Power Generation Facility (Investments – Other segment)

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 are currently subleasing the Facility to the Dow Chemical Company (Dow).

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 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council Market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as 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. Subsequent litigation commenced between us and TEM.

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 available for sale as a result of 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 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 2003 Consolidated Statement of Operations.

See further discussion in the "Power Generation Facility and TEM Litigation" section of Note 7.

11. BENEFIT PLANS

We sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees 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. We implemented FSP FAS 106-2 in the second quarter of 2004, retroactive to the first quarter of 2004. 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. As a result of implementing FSP FAS 106-2, the tax-free subsidy reduced 2004's 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 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 plan's measurement date of December 31, 2005, 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, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Service Cost	93	86	42	41
Interest Cost	228	228	107	117
Participant Contributions	-	-	20	18
Actuarial (Gain) Loss	191	379	(320)	(130)
Benefit Payments	(273)	(273)	(118)	(109)
Projected Obligation at December 31	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,555	$ 3,180	$ 1,093	$ 950
Actual Return on Plan Assets	224	409	70	98
Company Contributions	637	239	107	136
Participant Contributions	-	-	20	18
Benefit Payments	(273)	(273)	(118)	(109)
Fair Value of Plan Assets at December 31	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Funded Status:				
Funded Status at December 31	$ (204)	$ (553)	$ (659)	$ (1,007)
Unrecognized Net Transition Obligation	-	-	152	179
Unrecognized Prior Service Cost (Benefit)	(9)	(9)	5	5
Unrecognized Net Actuarial Loss	1,266	1,040	471	795
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

Amounts Recognized in the Balance Sheets as of December 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Prepaid Benefit Costs	$ 1,099	$ 524	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(31)	(28)
Additional Minimum Liability	(35)	(566)	N/A	N/A
Intangible Asset	6	36	N/A	N/A
Pretax Accumulated Other Comprehensive Income	29	530	N/A	N/A
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

N/A = Not Applicable

Pension and Other Postretirement Plans' Assets

The asset allocations for our pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

Asset Category	Target Allocation 2006	Percentage of Plan Assets at Year End 2005	2004
		(in percentage)	
Equity Securities	70	66	68
Debt Securities	28	25	25
Cash and Cash Equivalents	2	9	7
Total	100	100	100

The asset allocations for our other postretirement benefit plans at the end of 2005 and 2004, and target allocation for 2006, by asset category, are as follows:

Asset Category	Target Allocation 2006	Percentage of Plan Assets at Year End 2005	2004
		(in percentage)	
Equity Securities	66	68	70
Debt Securities	31	30	28
Other	3	2	2
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 the $320 million and $200 million contributions at the end of 2005 and 2004, respectively, 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 2006 and January 2005.

The value of our pension plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The qualified plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 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	2005	2004
	(in millions)	
Qualified Pension Plans	$ 4,053	$ 3,918
Nonqualified Pension Plans	81	80
Total	$ 4,134	$ 3,998

Minimum Pension Liability

Our combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $204 million and $553 million at December 31, 2005 and 2004, respectively. 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, 2005 and 2004 were as follows:

	Underfunded Pension Plans	
	As of December 31,	
	2005	2004
	(in millions)	
Projected Benefit Obligation	$ 84	$ 2,978
Accumulated Benefit Obligation	81	2,880
Fair Value of Plan Assets	-	2,406
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	81	474

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 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

We made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, to meet our goal of fully funding all qualified pension plans by the end 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	
	2005	2004	2005	2004
	(in percentages)			
Discount Rate	5.50	5.50	5.65	5.80
Rate of Compensation Increase	5.90 (a)	3.70	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

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 Moody's 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 method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching 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, 2005 and 2004 under this method was 5.50% for pension plans and 5.65% and 5.80%, respectively, for other postretirement benefit plans.

For 2005, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.9%.

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	2006	2005	2006	2005
	(in millions)			
Required Contributions (a)	$ 8	$ 10	N/A	N/A
Additional Discretionary Contributions	-	626 (b)	$ 96	$ 107

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor and to fund nonqualified benefit payments.

(b) 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 plans is based on the minimum amount required by the U.S. Department of Labor and the amount to fund nonqualified benefit payments, 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. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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)	
2006	$ 291	$ 117	$ (9)
2007	305	125	(10)
2008	316	133	(10)
2009	335	140	(11)
2010	344	148	(11)
Years 2011 to 2015, in Total	1,811	857	(65)

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 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
	(in millions)					
Service Cost	$ 93	$ 86	$ 80	$ 42	$ 41	$ 42
Interest Cost	228	228	233	107	117	130
Expected Return on Plan Assets	(314)	(292)	(318)	(92)	(81)	(64)
Amortization of Transition (Asset) Obligation	-	2	(8)	27	28	28
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	55	17	11	25	36	52
Net Periodic Benefit Cost (Credit)	61	40	(3)	109	141	188
Capitalized Portion	(17)	(10)	(3)	(33)	(46)	(43)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 44	$ 30	$ (6)	$ 76	$ 95	$ 145

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		
	2005	2004	2003	2005	2004	2003
	(in percentage)					
Discount Rate	5.50	6.25	6.75	5.80	6.25	6.75
Expected Return on Plan Assets	8.75	8.75	9.00	8.37	8.35	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 2005 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 8.75% for 2005. 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 increased to 8.37%.

The health care trend rate assumptions used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	2005	2004
Initial	9.0%	10.0%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2009	2009

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	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	263	(215)

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. Our contributions to the plan are 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled $57 million in 2005, $55 million in 2004 and $57 million in 2003.

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 2005, 2004 and 2003.

12. STOCK-BASED COMPENSATION

The Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was originally adopted by the Board of Directors and shareholders in 2000. The amended and restated version was adopted by the Board of Directors and shareholders in 2005.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance units and stock options. Our outstanding restricted stock units generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the 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. We awarded 165,743, 105,852 and 105,910 restricted stock units, including units awarded for dividends, with weighted-average grant-date fair values of $35.67, $32.03 and $22.17 per unit in 2005, 2004 and 2003, respectively. 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.

We awarded 300,000 restricted shares in 2004 that vest over periods ranging from one to eight years and we have not awarded any other restricted shares. Compensation cost is recorded over the vesting period based on the market value of $30.76 per unit on the grant date.

Performance units are generally equal in value to shares of AEP common stock except that the number of performance units held is multiplied by a performance factor which can range from 0% to 200% to determine the number of performance units realized. 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 (HR Committee). Performance units are typically paid in cash at the end of a three-year vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units until the end of the participant's AEP career (career shares). Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and phantom stock units accrue as additional units. We awarded 1,012,597, 119,000 and 1,066,198 performance units with grant-date fair values of $34.02, $30.76 and $28.02 per unit in 2005, 2004 and 2003, respectively. In addition, AEP awarded 89,138, 61,079 and 51,388 additional units as reinvested dividends on outstanding performance units and phantom stock units with weighted-average grant-date fair values of $36.25, $32.92 and $25.64 per unit in 2005, 2004 and 2003, respectively. In 2005, the HR Committee certified a performance factor of 123.1% for performance units originally granted for the December 10, 2003 through December 31, 2004 performance period. As a result, 946,789 performance units were deferred into phantom stock units, which will generally vest, subject to the participant's continued employment, on December 31, 2006. The performance factor was zero for all other performance periods that the HR Committee reviewed in 2005, 2004 and 2003. Therefore, no other performance units were earned or deferred into phantom stock units during these years.

The compensation cost for performance units is recorded over the vesting period and the liability for both the performance units and phantom stock units is adjusted for changes in fair market value.

Under the Plan, the exercise price of all stock option grants must equal or exceed the market price of AEP's common stock on the date of grant, and in accordance with APB 25, we do not record compensation expense. We adopted SFAS 123R effective January 1, 2006, which resulted in the recording of compensation expense for stock-based compensation (see "SFAS 123R" in section of Note 2). We historically granted options with a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year 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 2005, 2004 and 2003 is as follows:

	2005		2004		2003	
	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	8,230	$ 33	9,095	$ 33	8,787	$ 34
Granted	10	39	149	31	928	28
Exercised	(1,886)	37	(525)	27	(23)	27
Forfeited	(132)	32	(489)	34	(597)	33
Outstanding at end of year	6,222	34	8,230	33	9,095	33
Options exercisable at end of year	5,199	$ 35	6,069	$ 35	3,909	$ 36
Weighted average exercise price of options:						
Granted above Market Price		N/A		N/A		N/A
Granted at Market Price		$ 39		$ 31		$ 28

The following table summarizes information about AEP stock options outstanding at December 31, 2005:

Options Outstanding

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price
$25.73 - $27.95	1,610	6.6	$ 27.36
$30.76 - $38.65	4,140	3.9	35.45
$43.79 - $49.00	472	4.3	46.11
	6,222	4.6	34.16

Options Exercisable

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Exercise Price
$25.73 - $27.95	696	$ 27.25
$30.76 - $35.63	4,031	35.56
$43.79 - $49.00	472	46.11
	5,199	35.40

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:

	2005	2004	2003
Risk Free Interest Rate	4.14%	4.14%	3.92%
Expected Life	7 years	7 years	7 years
Expected Volatility	24.63%	28.17%	27.57%
Expected Dividend Yield	4.00%	4.84%	4.86%
Weighted average fair value of options:			
Granted above Market Price	N/A	N/A	N/A
Granted at Market Price	$ 7.60	$ 6.06	$ 5.26

13. BUSINESS SEGMENTS

We identify our reportable segments based on the nature of the product and services and geography. Our segments are organized based on the manner in which management makes operating decisions and assesses performance. 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.

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 includes 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 a limited investment in the generation and supply of power in Mexico, which was sold in February 2006. We also sold our generation assets in the U.K. and China in 2004 and our generation assets in the Pacific Rim in 2005 (see "Dispositions" section of Note 10).

Our segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.
- Operations of LIG, including Jefferson Island Storage & Hub, LLC, were classified as Discontinued Operations during 2003 and were sold during 2004. The remaining gas pipeline and storage assets were disposed of in 2005 with the sale of HPL (see "Dispositions" section of Note 10).

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.
- UK Operations were classified as Discontinued Operations during 2003 and were sold during 2004.

Investments – Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.
- Four IPPs were sold during 2004.

The tables below present segment income statement information for the twelve months ended December 31, 2005, 2004 and 2003 and balance sheet information for the years ended December 31, 2005 and 2004. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2005							
Revenues from:							
External Customers	$ 11,193	$ 463	$ -	$ 455	$ -	$ -	$ 12,111
Other Operating Segments	203	(181)	-	17	3	(42)	-
Total Revenues	$ 11,396	$ 282	$ -	$ 472	$ 3	$ (42)	$ 12,111
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,020	$ (31)	$ -	$ 93	$ (53)	$ -	$ 1,029
Discontinued Operations, Net of Tax	-	5	(2)	24	-	-	27
Extraordinary Loss, Net of Tax	(225)	-	-	-	-	-	(225)
Cumulative Effect of Accounting Changes, Net of Tax	(17)	-	-	-	-	-	(17)
Net Income (Loss)	$ 778	$ (26)	$ (2)	$ 117	$ (53)	$ -	$ 814
Depreciation and Amortization Expense	$ 1,285	$ 2	$ -	$ 30	$ 1	$ -	$ 1,318
Gross Property Additions	2,755	2	-	7	-	-	2,764

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2004							
Revenues from:							
External Customers	$ 10,664	$ 3,068	$ -	$ 513	$ -	$ -	$ 14,245
Other Operating Segments	105	50	-	36	7	(198)	-
Total Revenues	$ 10,769	$ 3,118	$ -	$ 549	$ 7	$ (198)	$ 14,245
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,175	$ (51)	$ -	$ 74	$ (71)	$ -	$ 1,127
Discontinued Operations, Net of Tax	-	(12)	91	4	-	-	83
Extraordinary Loss, Net of Tax	(121)	-	-	-	-	-	(121)
Net Income (Loss)	$ 1,054	$ (63)	$ 91	$ 78	$ (71)	$ -	$ 1,089
Depreciation and Amortization Expense	$ 1,256	$ 11	$ -	$ 32	$ 1	$ -	$ 1,300
Gross Property Additions	1,471	132	-	34	-	-	1,637

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2003							
Revenues from:							
External Customers	$ 11,030	$ 3,100	$ -	$ 703	$ -	$ -	$ 14,833
Other Operating Segments	130	27	-	52	11	(220)	-
Total Revenues	$ 11,160	$ 3,127	$ -	$ 755	$ 11	$ (220)	$ 14,833
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 1,223	$ (290)	$ -	$ (282)	$ (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)	$ 1,459	$ (403)	$ (529)	$ (288)	$ (129)	$ -	$ 110
Depreciation and Amortization Expense	$ 1,250	$ 18	$ -	$ 39	$ -	$ -	$ 1,307
Gross Property Additions	1,288	24	-	10	-	-	1,322

	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
As of December 31, 2005							
Total Property, Plant and Equipment	$ 38,283	$ 2	$ -	$ 833	3	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	1	-	112	1	-	14,837
Total Property, Plant and Equipment – Net	$ 23,560	$ 1	$ -	$ 721	$ 2	$ -	$ 24,284
Total Assets	$ 34,339	$ 1,199 (c)	$ 632 (d)	$ 509	$ 9,463	$ (9,970)	$ 36,172
Assets Held for Sale	44	-	-	-	-	-	44
Investments in Equity Method Subsidiaries	-	-	-	52	-	-	52
As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,014	$ 445	$ -	$ 832	$ 3	$ -	$ 37,294
Accumulated Depreciation and Amortization	14,363	43	-	86	1	-	14,493
Total Property, Plant and Equipment – Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,148	1,789	221 (e)	2,071	8,093	(9,686)	34,636
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 AEP's investments in subsidiary companies.

(c) Total Assets of $1.2 billion for the Investments-Gas Operations segment include $429 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $770 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.

(d) Total Assets of $632 million for the Investments-UK Operations segment include $613 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $19 million in assets represents cash equivalents with value-added tax receivables.

(e) 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.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying 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. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's 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. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment 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 whether 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.

Depending on the exposure, we designate a hedging instrument as a fair value hedge or a 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), 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 earnings 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) until the period the hedged item affects earnings. We recognize any hedge ineffectiveness in earnings immediately during the period of change.

Fair Value Hedging Strategies

Prior to the sale of HPL in the first quarter of 2005, to hedge the risks associated with our domestic gas pipeline and storage activities, we entered into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of this hedging activity was to protect the natural gas inventory against changes in fair value due to changes in 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 we anticipated at the time the transaction was structured. In the third quarter of 2004, the gas-related 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 2005, 2004 and 2003, we recognized

a pretax loss of approximately $0 million, $27.0 million and $3.4 million, respectively, in Revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy.

We enter into interest rate derivative transactions in order to manage interest rate risk exposure. The interest rate swap transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged in Interest Expense. During 2005, 2004 and 2003, we recognized no hedge ineffectiveness related to these swaps.

Cash Flow Hedging Strategies

We may 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 foreign currencies, the decline in value of future foreign currency cash flows 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. The impact of these hedges, which is immaterial, is included in Operating Expenses. We do not hedge all foreign currency exposure.

We enter into interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate swap transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. We reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2005 and 2003, we reclassified immaterial amounts into earnings due to hedge ineffectiveness. 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 in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative contracts to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2005, 2004 and 2003, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

We entered 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). Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues. During 2005, 2004 and 2003, we recognized immaterial amounts in earnings related to hedge ineffectiveness. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2005 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months
	(in millions)			
Power and Gas	$ 11	$ 20	$ (6)	$ (5)
Interest Rate	3	-	(21)(a)	(2)
	$ 14	$ 20	$ (27)	$ (7)

(a) Includes $1 million loss recorded in an equity investment.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2004 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months
	(in millions)			
Power and Gas	$ 88	$ (60)	$ 23	$ (26)
Interest Rate	1	(23)	(23)(a)	4
	$ 89	$ (83)	$ -	$ (22)

(a) Includes $3 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, 2005, the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows related to forecasted transactions is twelve months.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2005:

	Amount
	(in millions)
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
Balance at December 31, 2004	-
Changes in fair value	(5)
Reclasses from AOCI to net earnings	(22)
Ending Balance, December 31, 2005	$ (27)

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, 2005 and 2004 are summarized in the following tables.

	2005		2004	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 12,226	$ 12,416	$ 12,287	$ 12,813
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	-	66	67

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 Held for Sale on our Consolidated Balance Sheets, are recorded at market value in accordance with SFAS 115. At December 31, 2005 and 2004, the fair values of the trust investments were $1.1 billion and $1.2 billion, respectively, and had a cost basis of $989 million and $1 billion, respectively. The change in market value in 2005, 2004 and 2003 was a net unrealized gain of $28 million, $41 million and $53 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary loss and cumulative effect of accounting changes as reported are as follows:

	Year Ended December 31,		
	2005	2004	2003
		(in millions)	
Federal:			
Current	$ 375	$ 262	$ 297
Deferred	28	263	34
Total	403	525	331
State and Local:			
Current	25	49	19
Deferred	4	(3)	1
Total	29	46	20
International:			
Current	(2)	1	7
Deferred	-	-	-
Total	(2)	1	7
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 430	$ 572	$ 358

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,		
	2005	2004	2003
		(in millions)	
Net Income	$ 814	$ 1,089	$ 110
Discontinued Operations (net of income tax of $(30) million, $75 million and $(312) million in 2005, 2004 and 2003, respectively)	(27)	(83)	605
Extraordinary Loss, (net of income tax of $(121) million and $(64) million in 2005 and 2004, respectively)	225	121	-
Cumulative Effect of Accounting Changes (net of income tax of $(9) million and $138 million in 2005 and 2003, respectively)	17	-	(193)
Preferred Stock Dividends	7	6	9
Income Before Preferred Stock Dividends of Subsidiaries	1,036	1,133	531
Income Taxes Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	430	572	358
Pretax Income	$ 1,466	$ 1,705	$ 889
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 513	$ 597	$ 311
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	39	36	34
Asset Impairments and Investment Value Losses	-	-	23
Investment Tax Credits (net)	(32)	(29)	(33)
Tax Effects of International Operations	(2)	1	8
Energy Production Credits	(18)	(16)	(15)
State Income Taxes	19	30	13
Removal Costs	(14)	(12)	(6)
AFUDC	(14)	(11)	(10)
Medicare Subsidy	(13)	(10)	-
Tax Reserve Adjustments	(11)	(14)	13
Other	(37)	-	20
Total Income Taxes as Reported Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	$ 430	$ 572	$ 358
Effective Income Tax Rate	29.3%	33.5%	40.3%

The following table shows our elements of the net deferred tax liability and the significant temporary differences.

	As of December 31,	
	2005	2004
	(in millions)	
Deferred Tax Assets	$ 2,085	$ 2,280
Deferred Tax Liabilities	(6,895)	(7,099)
Net Deferred Tax Liabilities	$ (4,810)	$ (4,819)
Property Related Temporary Differences	$ (3,302)	$ (3,273)
Amounts Due From Customers For Future Federal Income Taxes	(186)	(184)
Deferred State Income Taxes	(384)	(452)
Transition Regulatory Assets	(176)	(211)
Securitized Transition Assets	(232)	(258)
Regulatory Assets	(446)	(578)
Accrued Pensions	(345)	(158)
Deferred Income Taxes on Other Comprehensive Loss	14	186
All Other (net)	247	109
Net Deferred Tax Liabilities	$ (4,810)	$ (4,819)

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 System's current consolidated federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current 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.

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 Agent's 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 management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2005, the Company has total provisions for uncertain tax positions of approximately $136 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.

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% (when fully phased-in in 2010) on a percentage of "qualified production activities income." For 2005 and for 2006, the deduction is 3% of qualified production activities income. The deduction increases to 6% 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. The FERC has issued an order that states the deduction is a special deduction that reduces the amount of income taxes due from energy sales. While the U.S. Treasury has issued proposed regulations on the calculation of the deduction, these proposed regulations lack clarity as to determination of qualified production activities income as it relates to utility operations. We believe that the special deduction for 2006 will not materially affect our results of operations, cash flows, or financial condition.

On August 8, 2005 the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of Integrated Gasification Combined Cycle (IGCC) plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP has announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. The United States Treasury Department was to announce by February 6, 2006 the program whereby taxpayers could apply for and be allocated these credits. The Treasury Department has yet to define its program. We cannot predict if AEP will be allocated any of these tax credits.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over 84-months in lieu of taking a depreciation deduction over 20-years. This act also allows for the transfer ("poured-over") of funds held in non-qualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the non-qualified funds are poured-over, the funds are poured-over over the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for non-qualified funds. We believe that the tax law changes discussed in this paragraph will not materially affect our results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. We believe that the application of these tax acts will not materially affect our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities of $83 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Tax Expense and, for the Ohio companies, established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by $22 million.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 was approximately $2 million.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0% to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance policies; all of which will not have a material impact on future results of operations and cash flows.

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 Maintenance and Other Operation 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,		
	2005	2004	2003
		(in millions)	
Lease Payments on Operating Leases	$ 307	$ 317	$ 344
Amortization of Capital Leases	57	54	64
Interest on Capital Leases	13	11	9
Total Lease Rental Costs	$ 377	$ 382	$ 417

Property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets are as follows:

	December 31, 2005	December 31, 2004
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 95	$ 91
Distribution	15	15
Other	331	323
Total Property, Plant and Equipment Under Capital Leases	441	429
Accumulated Amortization	190	186
Net Property, Plant and Equipment Under Capital Leases	$ 251	$ 243
Obligations Under Capital Leases		
Noncurrent Liability	$ 193	$ 190
Liability Due Within One Year	58	53
Total Obligations Under Capital Leases	$ 251	$ 243

Future minimum lease payments consisted of the following at December 31, 2005:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2006	$ 73	$ 313
2007	68	288
2008	45	264
2009	29	251
2010	16	249
Later Years	93	2,018
Total Future Minimum Lease Payments	$ 324	$ 3,383
Less Estimated Interest Element	73	
Estimated Present Value of Future Minimum Lease Payments	$ 251	

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct, own and lease the Gavin Scrubber for the Gavin Plant 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 with a nonaffiliated third party. For the first half of 2003, operating lease payments related to the Gavin Scrubber were recorded as operating lease expense by OPCo. In our 2003 Consolidated Statement of Operations, these lease payments are included in Maintenance and Other Operation. After July 1, 2003, OPCo has recorded the depreciation, interest and other operating expenses of JMG and has eliminated JMG's rental revenues against OPCo's 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 company as of December 31, 2005 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.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the lease term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2005, the maximum potential loss was approximately $31 million ($20 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other rail car lease arrangements that do not utilize this type of structure.

17. FINANCING ACTIVITIES

Common Stock

2005

Common Stock Repurchase

In February 2005, our Board of Directors authorized the repurchase up to $500 million of our common stock from time to time through 2006. In March 2005, we purchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May and we received a purchase price adjustment of $6.45 million based on the actual cost of the shares repurchased. Based on this adjustment, our actual stock purchase price averaged $34.18 per share. Management has not established a timeline for the buyback of the remaining stock under this plan.

Equity Units and Remarketing of Senior Notes

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consisted of a forward purchase contract and a senior note. In June 2005, we remarketed and settled $345 million of our 5.75% senior notes at a new interest rate of 4.709%. The senior notes mature on August 16, 2007. We did not receive any proceeds from the mandatory remarketing.

Issuance of Common Stock

On August 16, 2005, we issued approximately 8.4 million shares of common stock in connection with the settlement of forward purchase contracts that formed a part of our outstanding 9.25% equity units. In exchange for $50 per equity unit, holders of the equity units received 1.2225 shares of AEP common stock for each purchase contract and cash in lieu of fractional shares. Each holder was not required to make any additional cash payment. The equity unit holder's purchase obligation was satisfied from the proceeds of a portfolio of U.S. Treasury securities held in a collateral account that matured on August 1, 2005. The portfolio of U.S. Treasury securities was acquired in connection with the June 2005 remarketing of the senior notes discussed above.

2003

In 2003, we issued 56 million shares and received net proceeds of $1.1 billion.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2005, 2004 and 2003:

Shares of Common Stock	Issued	Held in Treasury
Balance January 1, 2003	347,835,212	8,999,992
Issued	56,181,201	-
Treasury stock:		
Acquisition	-	-
Retirement	-	-
Balance December 31, 2003	404,016,413	8,999,992
Issued	841,732	-
Treasury stock:		
Acquisition	-	-
Retirement	-	-
Balance December 31, 2004	404,858,145	8,999,992
Issued	10,360,685	-
Treasury stock:		
Acquisition	-	12,500,000
Retirement	-	-
Balance December 31, 2005	415,218,830	21,499,992

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2005			
	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	607,642	$ 61

	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	18
6.25% - 6.875% (c)	$100	950,000	482,450	48
Total Subject to Mandatory Redemption (c)				66
Total Preferred Stock				$ 127

(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, 2005, the subsidiaries had 14,487,597 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, 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.

(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 664,470 shares in 2005, 96,378 shares in 2004 and 86,210 shares in 2003.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2005	Interest Rate Range at December 31, 2005	Interest Rate Range at December 31, 2004	December 31, 2005	December 31, 2004
				(in millions)	
INSTALLMENT PURCHASE CONTRACTS (a)					
2006-2009	3.99%	2.70%-4.55%	1.75%-4.55%	$ 163	$ 163
2011-2022	4.14%	2.625%-6.10%	1.70%-6.10%	785	785
2023-2038	3.91%	2.625%-6.55%	1.125%-6.55%	987	825
SENIOR UNSECURED NOTES					
2005-2009	5.49%	3.60%-6.91%	2.879%-6.91%	1,973	3,459
2010-2017	5.21%	4.40%-6.375%	4.40%-6.375%	3,783	2,633
2032-2035	6.21%	5.625%-6.65%	5.625%-6.65%	2,125	1,625
FIRST MORTGAGE BONDS (b)					
2005-2008 (c)	6.93%	6.20%-7.75%	6.20%-8.00%	222	456
2025	-	-	8.00%	-	45
NOTES PAYABLE (d)					
2006-2017	6.08%	4.47%-15.25%	2.325%-15.25%	904	939
SECURITIZATION BONDS					
2007-2017	5.78%	5.01%-6.25%	3.54%-6.25%	648	698
NOTES PAYABLE TO TRUST					
2043	5.25%	5.25%	5.25%	113	113
EQUITY UNIT SENIOR NOTES					
2007	4.709%	4.709%	5.75%	345	345
OTHER LONG-TERM DEBT (e)				236	243
Equity Unit Contract Adjustment Payments				-	9
Unamortized Discount (net)				(58)	(51)
Total Long-term Debt Outstanding				12,226	12,287
Less Portion Due Within One Year				1,153	1,279
Long-term Portion				$ 11,073	$ 11,008

(a) For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.

(b) 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.

(c) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had balances of $18 million and $84 million in 2005 and 2004, respectively. Trust fund assets related to this obligation of $2 million and $72 million are included in Other Temporary Cash Investments and $21 million and $22 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at December 31, 2005 and 2004, respectively. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond has a balance of $8 million at December 31, 2005. Trust fund assets related to this obligation of $1 million are included in Other Temporary Cash Investments and $8 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at December 31, 2005. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(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) 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.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2005 IS PAYABLE AS FOLLOWS:

	2006	2007	2008	2009	2010	After 2010	Total
				(in millions)			
Principal Amount	$ 1,153	$ 1,243	$ 575	$ 927	$ 1,224	$ 7,162	$ 12,284
Unamortized Discount							(58)
							$ 12,226

Dividend Restrictions

Under the Federal Power Act, AEP's public utility subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

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. In addition, PSO and TCC had trusts that were deconsolidated in 2003 due to the implementation of FIN 46. The Junior Subordinated Debentures held in the trust for PSO and TCC were retired in 2004. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2005 and 2004, is included in Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2005 and 2004, are reported as Notes Payable to Trust within Long-term Debt.

The business trust is treated as a nonconsolidated subsidiary of its parent company. The only asset of the business trust is the subordinated debentures issued by its 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 on December 31, 2005 and 2004. 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.

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, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. As of December 31, 2005, 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 $25 million in January 2005 and the weighted average interest rate of commercial paper outstanding during the year was 2.50%. In September 2005, Moody's Investors Service upgraded AEP's commercial paper rating to Prime-2 from Prime-3.

At December 31, 2005 and 2004, we had $10 million and $23 million, respectively, in outstanding commercial paper related to JMG, reflected as Short-term Debt on our Consolidated Balance Sheets. This interest rate of the JMG commercial paper at December 31, 2005 and 2004 was 4.47% and 2.50%, respectively. 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.

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, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be taken off of AEP Credit's 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. AEP Credit continues 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.

AEP Credit's sale of receivables agreement expires on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 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 APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31,	
	2005	2004
	($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,925	$ 5,163
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 106	$ 80
Deferred Revenue from Servicing Accounts Receivable	$ 1	$ 1
Loss on Sale of Accounts Receivable	$ 18	$ 7
Average Variable Discount Rate	3.23%	1.50%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	$ 103	$ 78
Retained Interest if 20% Adverse Change in Uncollectible Accounts	$ 101	$ 76

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value December 31, 2005	Face Value December 31, 2004
	(in millions)	
Customer Accounts Receivable Retained	$ 826	$ 830
Accrued Unbilled Revenues Retained	374	665
Miscellaneous Accounts Receivable Retained	51	84
Allowance for Uncollectible Accounts Retained	(31)	(77)
Total Net Balance Sheet Accounts Receivable	1,220	1,502
Customer Accounts Receivable Securitized	516	435
Total Accounts Receivable Managed	$ 1,736	$ 1,937
Net Uncollectible Accounts Written Off	$ 74	$ 86

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 $30 million and $25 million at December 31, 2005 and 2004, respectively.

18. JOINTLY-OWNED ELECTRIC UTILITY PLANT

We have generating units that are jointly-owned with nonaffiliated companies. We are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Statements of Operations and the investments are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

		Company's Share December 31, 2005		Company's Share December 31, 2004	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in millions)			
W.C. Beckjord Generating Station (Unit No. 6)	12.5%	$ 16	$ -	$ 16	$ -
Conesville Generating Station (Unit No. 4)	43.5	85	8	85	1
J.M. Stuart Generating Station	26.0	266	35	210	61
Wm. H. Zimmer Generating Station	25.4	749	2	741	8
Dolet Hills Generating Station (Unit No. 1)	40.2	238	4	238	3
Flint Creek Generating Station (Unit No. 1)	50.0	94	2	94	1
Pirkey Generating Station (Unit No. 1)	85.9	460	10	457	2
STP Generation Station (Units No. 1 and 2) (a)	0.0	-	-	2,387	2
Oklaunion Generating Station (Unit No. 1) (b)	78.1	415	3	412	2
Transmission	(c)	63	1	62	4

(a) Included in Assets Held for Sale on our Consolidated Balance Sheets. Sale of STP was completed in May 2005. We owned 25.2% of STP at December 31, 2004.

(b) TCC's 7.8% interest in Oklaunion amounted to $39,977 and $39,735 at December 31, 2005 and 2004. These amounts are included in Assets Held for Sale on our Consolidated Balance Sheets.

(c) Varying percentages of ownership.

The amount of accumulated depreciation related to our share of jointly-owned facilities is $1.2 billion and $2.1 billion at December 31, 2005 and 2004, respectively. Of these amounts, $20 million and $991 million is included in Assets Held for Sale on our Consolidated Balance Sheets at December 31, 2005 and 2004, respectively. The remainder is included in Accumulated Depreciation and Amortization.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

(In Millions – Except Per Share Amounts)	2005 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 3,065	$ 2,819	$ 3,328	$ 2,899
Operating Income	660	455	624	188
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	351	221	365	92
Extraordinary Loss, Net of Tax (a)	-	-	-	(225)
Net Income (Loss)	355	221	387	(149)
Basic Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share	0.90	0.58	0.99	(0.38)
Diluted Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (c)	0.90	0.57	0.94	0.23
Extraordinary Loss per Share (b)	-	-	-	(0.57)
Earnings (Loss) per Share (d)	0.90	0.58	0.99	(0.38)

(In Millions – Except Per Share Amounts)	2004 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 3,404	$ 3,457	$ 3,819	$ 3,565
Operating Income	634	420	644	285
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	289	151	412	275
Extraordinary Loss, Net of Tax (a)	-	-	-	(121)
Net Income	282	100	530	177
Basic and Diluted Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes (e)	0.73	0.38	1.04	0.69
Basic and Diluted Extraordinary Loss per Share	-	-	-	(0.31)
Basic and Diluted Earnings per Share	0.71	0.25	1.34	0.45

(a) See "Extraordinary Items" section of Note 2 for a discussion of the extraordinary loss booked in the fourth quarters of 2005 and 2004.

(b) Amounts for 2005 do not add to $(0.58) for Extraordinary Loss per Share due to differences between the weighted average number of shares outstanding for the fourth quarter of 2005 and the year 2005.

(c) Amounts for 2005 do not add to $2.63 for Diluted Earnings (Loss) per Share before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes due to rounding.

(d) Amounts for 2005 do not add to $2.08 for Diluted Earnings (Loss) per Share due to rounding.

(e) Amounts for 2004 do not add to $2.85 for Basic and Diluted Earnings per Share before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes due to rounding.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA
(in thousands)

	2005	2004	2003	2002	2001
STATEMENTS OF INCOME DATA					
Total Revenues	$ 1,892,602	$ 1,741,485	$ 1,650,505	$ 1,609,047	$ 1,615,762
Operating Income	$ 286,660	$ 269,559	$ 204,654	$ 206,825	$ 225,572
Income Before Cumulative Effect of Accounting Change	$ 146,852	$ 133,222	$ 89,548	$ 73,992	$ 75,788
Cumulative Effect of Accounting Change, Net of Tax	-	-	(3,160)	-	-
Net Income	$ 146,852	$ 133,222	$ 86,388	$ 73,992	$ 75,788
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 5,962,282	$ 5,717,480	$ 5,465,207	$ 5,209,982	$ 5,109,424
Accumulated Depreciation and Amortization	2,822,558	2,708,122	2,597,634	2,428,835	2,306,932
Net Property, Plant and Equipment	$ 3,139,724	$ 3,009,358	$ 2,867,573	$ 2,781,147	$ 2,802,492
Total Assets	$ 5,262,309	$ 4,863,222	$ 4,654,171	$ 4,832,832	$ 4,627,610
Common Shareholder's Equity	$ 1,220,092	$ 1,091,498	$ 1,078,047	$ 1,018,653	$ 860,570
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 8,084	$ 8,084	$ 8,101	$ 8,101	$ 8,736
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	$ -	$ 61,445	$ 63,445	$ 64,945	$ 64,945
Long-term Debt (a)	$ 1,444,940	$ 1,312,843	$ 1,339,359	$ 1,617,062	$ 1,652,082
Obligations Under Capital Leases (a)	$ 43,976	$ 50,732	$ 37,843	$ 50,848	$ 61,933

(a) Including portion due within one year.

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 581,000 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. Our River Transportation Division (RTD) provides barging services to affiliates and nonaffiliated companies. The revenues from barging are the majority of our other revenues.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold. As a result of CSPCo's acquisition of the Waterford Plant (offset by the retirement of Conesville Plant Units 1 and 2) and APCo's acquisition of the Ceredo Generating Station, we, as a member with a generating capacity surplus, are expecting to receive reduced capacity revenues in 2006. 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 member's 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 member's 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 agreements and the SIA. 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 the current SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities are shared among AEP East companies and AEP 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 companies' and AEP 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 companies and AEP West companies in the event the pre-merger activity level is exceeded. The capacity-based allocation mechanism was triggered in July 2005, July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the respective year.

The current allocation methodology was established at the time of the AEP-CSW merger. On November 1, 2005, AEPSC, on behalf of all AEP East companies and AEP West companies, filed with the FERC a proposed allocation methodology to be used beginning in 2006. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for the sharing of all such margins among all AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from our proposal. AEPSC requested that the new methodology be effective on a prospective basis after the FERC's approval. Management is unable to predict the ultimate effect of this filing on the AEP East companies' and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, 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 behalf of AEP East companies and AEP West companies and activity conducted by any Registrant Subsidiary pursuant to the SIA.

Results of Operations

2005 Compared to 2004

Reconciliation of Year Ended December 31, 2004 to Year Ended December 31, 2005
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2004		$ 133
Changes in Gross Margin:		
Retail Margins	69	
Off-System Sales Margins (a)	7	
Transmission Revenues	(15)	
Other Revenues	4	
Total Change in Gross Margin		65
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(38)	
Taxes Other Than Income Taxes	(11)	
Depreciation and Amortization	1	
Other Income	2	
Interest Expense	4	
Total Change in Operating Expenses and Other		(42)
Income Tax Expense		(9)
Year Ended December 31, 2005		$ 147

(a) Includes firm wholesale sales to municipals and cooperatives.

Income Before Cumulative Effect of Accounting Change increased $14 million to $147 million in 2005. The key drivers of the increase were a $65 million increase in Gross Margin partially offset by a $38 million increase in Other Operation and Maintenance expenses and an $11 million increase in Taxes Other Than Income Taxes.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $69 million primarily due to increases in retail sales to residential and commercial customers and capacity settlement revenues of $39 million under the SIA related to the increase in an affiliate's peak load. Increased retail sales primarily reflect warmer summer weather and colder weather in December 2005. Cooling degree days were approximately 20% higher than normal and approximately 60% higher than 2004. Heating degree days were 13% higher than normal and prior year for December.
- Transmission Revenues decreased $15 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $38 million primarily due to an $18 million increase in power generation maintenance expense due to planned maintenance at Tanners Creek Plant and a $5 million increase in system dispatch cost related to operation in PJM. A $12 million increase in distribution maintenance expense for overhead power lines included the January 2005 ice storm and reliability initiatives.
- Taxes Other Than Income Taxes increased due to a $7 million increase in real and personal property taxes and a $2 million increase in payroll-related taxes.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income.

2004 Compared to 2003

Reconciliation of Year Ended December 31, 2003 to Year Ended December 31, 2004
Income Before Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2003		$ 90
Changes in Gross Margin:		
Retail Margins	34	
Off-system Sales Margins (a)	8	
Other Revenues	11	
Total Change in Gross Margin		53
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	4	
Asset Impairments	10	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	(2)	
Other Income	(5)	
Interest Expense	14	
Total Change in Operating Expenses and Other		20
Income Tax Expense		(30)
Year Ended December 31, 2004		$ 133

(a) Includes firm wholesale sales to municipals and cooperatives.

Income Before Cumulative Effect of Accounting Change increased $43 million to $133 million in 2004. The key driver of the increase was a $53 million increase in Gross Margin.

The major components of our increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $34 million primarily due to increases in retail sales to commercial and industrial customers reflecting the economic recovery and the end of amortization of Cook Plant outage settlements.
- Other Revenues increased $11 million primarily due to increased revenues for barging coal to our affiliated companies' plants. Related expenses which offset the revenue increases are included in Other Operation on the Consolidated Statements of Income resulting in RTD earning only its approved return.

Operating Expenses and Other changed between years as follows:

- Asset Impairments decreased due to a $10 million write-down in 2003 of western coal lands (see "Blackhawk Coal Company" section of Note 10).
- Interest Expense 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 increase in Income Tax Expense of $30 million is primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings, unchanged since first quarter of 2003, are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Cash Flow

Cash flows for 2005, 2004 and 2003 were as follows:

	2005	2004	2003
		(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 511	$ 3,914	$ 3,237
Cash Flows From (Used For):			
Operating Activities	292,146	510,903	361,793
Investing Activities	(379,593)	(270,964)	(123,131)
Financing Activities	87,790	(243,342)	(237,985)
Net Increase (Decrease) in Cash and Cash Equivalents	343	(3,403)	677
Cash and Cash Equivalents at End of Period	$ 854	$ 511	$ 3,914

Operating Activities

Our net cash flows from operating activities were $292 million in 2005. We produced Net Income of $147 million during the period and noncash expense items of $171 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 was a $118 million change in Accrued Taxes, Net reflecting taxes paid during 2005.

Our net cash flows from operating activities were $511 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 Accrued Taxes, Net. 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 was made in March 2005 when the 2004 federal income tax return extension was filed.

Our net cash flows from operating activities were $362 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 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 was a $50 million change in net accounts receivable/payable related to the timing of settlements with our affiliates and $29 million related to Accrued Taxes, Net related to the timing of estimated federal income tax payments.

Investing Activities

Cash flows used for investing activities during 2005, 2004 and 2003 primarily reflect our construction expenditures of $299 million, $179 million and $163 million, respectively. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability. We also invested in capital projects to improve air quality and water intake systems.

Financing Activities

Our cash flows from financing activities were $88 million in 2005. We issued long-term debt and borrowed from our affiliates to fund construction expenditures.

Our cash flows used for financing activities were $243 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 a variable rate.

Financing activities for 2003 used $238 million of cash from operations primarily to redeem $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.

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, co-owners of Rockport Plant Unit 1, 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 as of December 31, 2005.

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 our Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2005:

Payment 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)	$ 93.7	$ -	$ -	$ -	$ 93.7
Interest on Fixed Rate Portion of Long-term Debt (b)	60.1	76.0	69.1	328.9	534.1
Fixed Rate Portion of Long-term Debt (c)	364.5	100.0	-	835.8	1,300.3
Variable Rate Portion of Long-term Debt (d)	-	-	45.0	102.0	147.0
Capital Lease Obligations (e)	9.2	21.1	6.5	20.7	57.5
Noncancelable Operating Leases (e)	100.7	194.1	186.3	949.8	1,430.9
Fuel Purchase Contracts (f)	255.3	330.1	265.4	204.8	1,055.6
Energy and Capacity Purchase Contracts (g)	0.4	0.2	-	-	0.6
Construction Contracts for Capital Assets (h)	95.8	33.1	-	-	128.9
Total	$ 979.7	$ 754.6	$ 572.3	$ 2,442.0	$ 4,748.6

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2005 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 16. Represents principal only excluding interest.
(d) See Note 16. Represents principal only excluding interest. Variable rate debt had an interest rate of 3.23% at December 31, 2005.
(e) See Note 15.
(f) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual cash flows of energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

As discussed in Note 11, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

Significant Factors

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and if the loss can be estimated. For details on our pending litigation and regulatory proceedings, See Note 4 – Rate Matters, Note 6 – Customer Choice and Industry Restructuring, and Note 7 – Commitments and Contingencies. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page M-1 for additional discussion of factors relevant to us.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits 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 AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our Consolidated Balance Sheet as of December 31, 2005 and the reasons for changes in our total MTM value as compared to December 31, 2004.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet
As of December 31, 2005
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 77,494	$ 640	$ -	$ 78,134
Noncurrent Assets	103,645	-	-	103,645
Total MTM Derivative Contract Assets	181,139	640	-	181,779
Current Liabilities	(68,126)	(2,462)	(444)	(71,032)
Noncurrent Liabilities	(79,081)	(228)	(6,850)	(86,159)
Total MTM Derivative Contract Liabilities	(147,207)	(2,690)	(7,294)	(157,191)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,932	$ (2,050)	$ (7,294)	$ 24,588

(a) See "Natural Gas Contracts with DETM" section of Note 17.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 34,573
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	331
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(734)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value due to Market Fluctuations During the Period (b)	545
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(783)
Total MTM Risk Management Contract Net Assets	33,932
Net Cash Flow & Fair Value Hedge Contracts	(2,050)
DETM Assignment (d)	(7,294)
Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 24,588

(a) 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.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in our Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(d) See "Natural Gas Contracts with DETM" section of Note 17.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents:

- The method of measuring 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 to give 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, 2005 (in thousands)

	2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 4,077	$ 2,282	$ 660	$ -	$ -	$ -	$ 7,019
Prices Provided by Other External Sources – OTC Broker Quotes (a)	11,125	7,556	7,206	3,635	-	-	29,522
Prices Based on Models and Other Valuation Methods (b)	(5,834)	(2,358)	(1,249)	1,938	4,630	264	(2,609)
Total	$ 9,368	$ 7,480	$ 6,617	$ 5,573	$ 4,630	$ 264	$ 33,932

(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.

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 the use of interest rate derivative transactions in order to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for the changes from December 31, 2004 to December 31, 2005. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)
Changes in Fair Value	(5)	2,494	2,489
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(2,430)	550	(1,880)
Ending Balance in AOCI December 31, 2005	$ (877)	$ (2,590)	$ (3,467)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,050 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

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, 2005, 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:

December 31, 2005 (in thousands)				December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$433	$720	$343	$124	$371	$1,211	$522	$178

VaR Associated with Debt Outstanding

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 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 $55 million and $53 million at December 31, 2005 and 2004, 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.

-This page intentionally left blank.-

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,445,866	$ 1,378,844	$ 1,302,269
Sales to AEP Affiliates	366,032	286,310	283,094
Other – Affiliated	46,719	42,968	34,972
Other – Nonaffiliated	33,985	33,363	30,170
TOTAL	1,892,602	1,741,485	1,650,505
EXPENSES			
Fuel and Other Consumables for Electric Generation	327,263	286,211	255,395
Purchased Electricity for Resale	48,378	37,013	28,327
Purchased Electricity from AEP Affiliates	306,117	272,452	274,400
Other Operation	476,560	473,234	487,712
Maintenance	202,909	168,304	158,281
Asset Impairments	-	-	10,300
Depreciation and Amortization	171,030	172,099	171,281
Taxes Other Than Income Taxes	73,685	62,613	60,155
TOTAL	1,605,942	1,471,926	1,445,851
OPERATING INCOME	286,660	269,559	204,654
Other Income (Expense):			
Interest Income	2,006	2,011	4,006
Allowance for Equity Funds Used During Construction	4,457	2,338	5,090
Interest Expense	(65,041)	(69,071)	(83,054)
INCOME BEFORE INCOME TAXES	228,082	204,837	130,696
Income Tax Expense	81,230	71,615	41,148
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	146,852	133,222	89,548
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, Net of Tax	-	-	(3,160)
NET INCOME	146,852	133,222	86,388
Preferred Stock Dividend Requirements including Capital Stock Expense	395	474	2,509
EARNINGS APPLICABLE TO COMMON STOCK	$ 146,457	$ 132,748	$ 83,879

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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, 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 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
Common Stock Dividends			(62,000)		(62,000)
Preferred Stock Dividends			(339)		(339)
Capital Stock Expense and Other		2,455	(56)		2,399
TOTAL					1,031,558
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $328				609	609
Minimum Pension Liability, Net of Tax of $22,116				41,073	41,073
NET INCOME			146,852		146,852
TOTAL COMPREHENSIVE INCOME					188,534
DECEMBER 31, 2005	$ 56,584	$ 861,290	$ 305,787	$ (3,569)	$ 1,220,092

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2005 and 2004
(in thousands)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 854	$ 511
Advances to Affiliates	-	5,093
Accounts Receivable:		
Customers	62,614	62,608
Affiliated Companies	127,981	124,134
Miscellaneous	1,982	4,339
Allowance for Uncollectible Accounts	(898)	(187)
Total Accounts Receivable	191,679	190,894
Fuel	25,894	27,218
Materials and Supplies	118,039	103,342
Risk Management Assets	78,134	52,141
Accrued Tax Benefits	51,846	-
Margin Deposits	17,115	5,400
Prepayments and Other	14,188	11,295
TOTAL	497,749	395,894
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,128,078	3,122,883
Transmission	1,028,496	1,009,551
Distribution	1,029,498	990,826
Other (including nuclear fuel and coal mining)	465,130	430,705
Construction Work in Progress	311,080	163,515
Total	5,962,282	5,717,480
Accumulated Depreciation, Depletion and Amortization	2,822,558	2,708,122
TOTAL - NET	3,139,724	3,009,358
OTHER NONCURRENT ASSETS		
Regulatory Assets	222,686	251,090
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,133,567	1,053,439
Long-term Risk Management Assets	103,645	52,256
Deferred Charges and Other	164,938	101,185
TOTAL	1,624,836	1,457,970
TOTAL ASSETS	$ 5,262,309	$ 4,863,222

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2005 and 2004

	2005	2004
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 93,702	$ -
Accounts Payable:		
General	139,334	92,916
Affiliated Companies	60,324	51,066
Long-term Debt Due Within One Year	364,469	-
Cumulative Preferred Stock Due Within One Year	-	61,445
Risk Management Liabilities	71,032	47,174
Customer Deposits	49,258	29,366
Accrued Taxes	56,567	123,159
Other	112,839	87,363
TOTAL	947,525	492,489
NONCURRENT LIABILITIES		
Long-term Debt	1,080,471	1,312,843
Long-term Risk Management Liabilities	86,159	36,815
Deferred Income Taxes	335,264	315,730
Regulatory Liabilities and Deferred Investment Tax Credits	710,015	677,260
Asset Retirement Obligations	737,959	711,769
Deferred Credits and Other	136,740	216,734
TOTAL	3,086,608	3,271,151
TOTAL LIABILITIES	4,034,133	3,763,640
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,084
Commitments and Contingencies (Note 7)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,290	858,835
Retained Earnings	305,787	221,330
Accumulated Other Comprehensive Income (Loss)	(3,569)	(45,251)
TOTAL	1,220,092	1,091,498
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,262,309	$ 4,863,222

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
OPERATING ACTIVITIES			
Net Income	$ 146,852	$ 133,222	$ 86,388
Adjustments for Noncash Items:			
Depreciation and Amortization	171,030	172,099	171,281
Accretion of Asset Retirement Obligations	47,368	39,825	37,150
Deferred Income Taxes	26,873	(5,548)	(14,894)
Deferred Investment Tax Credits	(7,725)	(7,476)	(7,431)
Cumulative Effect of Accounting Change, Net of Tax	-	-	3,160
Asset Impairments	-	-	10,300
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	21,273	13,082	(27,754)
Amoritization of Nuclear Fuel	56,038	52,455	44,276
Amortization of Cook Plant Outage Costs	-	-	40,000
Mark-to-Market of Risk Management Contracts	(7,331)	2,756	43,938
Pension Contributions to Qualified Plan Trusts	(90,668)	(3,888)	(9,437)
Unrecovered Fuel and Purchased Power Costs	(1,681)	(1,689)	37,501
Change in Other Noncurrent Assets	37,997	24,736	40,481
Change in Other Noncurrent Liabilities	(17,355)	8,526	16,444
Changes in Components of Working Capital:			
Accounts Receivable, Net	(785)	983	34,346
Fuel, Materials and Supplies	(13,373)	(10,977)	(7,320)
Accounts Payable	9,630	(1,304)	(85,312)
Accrued Taxes, Net	(118,438)	80,970	(29,370)
Customer Deposits	19,892	7,411	5,294
Other Current Assets	(12,927)	(478)	(3,353)
Other Current Liabilities	25,476	6,198	(23,895)
Net Cash Flows From Operating Activities	292,146	510,903	361,793
INVESTING ACTIVITIES			
Construction Expenditures	(298,632)	(179,414)	(163,391)
Change in Advances to Affiliates, Net	5,093	(5,093)	191,226
Purchases of Investment Securities	(606,936)	(901,356)	(656,557)
Sales of Investment Securities	556,667	862,976	579,932
Acquisitions of Nuclear Fuel	(52,579)	(50,865)	(76,177)
Proceeds from Sale of Assets	16,794	2,788	1,836
Net Cash Flows Used For Investing Activities	(379,593)	(270,964)	(123,131)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	123,761	268,057	64,434
Change in Advances from Affiliates, Net	93,702	(98,822)	98,822
Retirement of Long-term Debt	-	(304,017)	(350,000)
Retirement of Cumulative Preferred Stock	(61,445)	(2,011)	(1,500)
Principal Payments for Capital Lease Obligations	(5,889)	(6,916)	(7,366)
Dividends Paid on Common Stock	(62,000)	(99,293)	(40,000)
Dividends Paid on Cumulative Preferred Stock	(339)	(340)	(2,375)
Net Cash Flows From (Used For) Financing Activities	87,790	(243,342)	(237,985)
Net Increase (Decrease) in Cash and Cash Equivalents	343	(3,403)	677
Cash and Cash Equivalents at Beginning of Period	511	3,914	3,237
Cash and Cash Equivalents at End of Period	$ 854	$ 511	$ 3,914

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $59,339,000, $70,988,000 and $82,593,000 and for income taxes was $184,061,000, and $(2,244,000) and $94,440,000 in 2005, 2004 and 2003, respectively. Noncash capital lease acquisitions were $2,639,000, $20,557,000 and $3,216,000 in 2005, 2004 and 2003, respectively. Noncash construction expenditures included in Accounts Payable of $38,523,000, $16,530,000 and $21,487,000 were outstanding as of December 31, 2005, 2004 and 2003, respectively. Noncash acquisition of nuclear fuel included in Accounts Payable was $24,053,000 as of December 31, 2005.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's 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. The footnotes begin on page L-1.

	Footnote Reference
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Company-wide Staffing and Budget Review	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Other Losses	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Unaudited Quarterly Financial Information	Note 19

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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. As discussed in Note 11 to the consolidated financial statements, the Company adopted 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 27, 2006

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, Extraordinary Items and Cumulative Effect of Accounting Changes	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.	Company-wide Staffing and Budget Review	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Acquisitions, Dispositions, Impairments, Assets Held for Sale and Other Losses	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 nine of AEP's ten Registrant Subsidiaries is the generation, transmission and distribution of electric power. TCC and TNC are completing the final stage of exiting the generation business. AEGCo is an electricity generation business. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 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.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale power markets. Wholesale power markets are generally market-based and are not cost-based regulated unless a wholesaler negotiates and files a cost-based rate contract with the FERC or 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 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).

For the periods presented, AEP and its subsidiaries were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (PUHCA 1935). The Energy Policy Act of 2005 repealed PUHCA 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA 2005). With the repeal of PUHCA 1935, the SEC no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over holding company related activities has been transferred to the FERC. Regulations and required reporting under PUHCA 2005 are reduced compared to PUHCA 1935. Specifically, the FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records of any company within a holding company system.

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 (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 Equity Earnings of Unconsolidated Subsidiaries on our consolidated financial statements. OPCo and SWEPCo also consolidate VIEs in accordance with FASB Interpretation Number (FIN) 46 (revised December 2003) "Consolidation of Variable Interest Entities" (FIN 46R) (see "SWEPCo" section of Note 8 and "Gavin Scrubber Financing Arrangement" section of Note 15). CSPCo, OPCo, 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 assets and liabilities 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, and in Arkansas by SWEPCo in September 1999. 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, unbilled electricity revenue, valuation 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 and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately 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 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 our plants are included in operating expenses.

The Registrant Subsidiaries implemented SFAS 143 effective January 1, 2003 and FIN 47 effective December 31, 2005 (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.

Property, Plant and Equipment and Equity Investments are disclosed as regulated/nonregulated by functional class within the Depreciation, Depletion and Amortization section below.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, 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:

2005	AEGCo Regulated				KPCo Regulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 684,721	$ 379,641	3.5%	31	$ 472,575	$ 151,389	3.8%	40-50
Transmission	-	-	N.M.	N.M.	386,945	119,048	1.7%	25-75
Distribution	-	-	N.M.	N.M.	456,063	136,106	3.5%	11-75
CWIP	12,252	2,226	N.M.	N.M.	35,461	(1,126)	N.M.	N.M.
Other	2,251	1,058	16.0%	N.M.	57,776	20,241	9.4%	N.M.
Total	$ 699,224	$ 382,925			$ 1,408,820	$ 425,658		

	AEGCo Nonregulated				KPCo Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Other	$ 118	$ -	N.M.	N.M.	$ 5,606	$ 159	2.0%	N.M.

2004	AEGCo Regulated				KPCo Regulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 681,254	$ 364,779	3.5%	31	$ 462,641	$ 139,677	3.8%	40-50
Transmission	-	-	N.M.	N.M.	385,667	113,199	1.7%	25-75
Distribution	-	-	N.M.	N.M.	438,766	127,858	3.5%	11-75
CWIP	7,729	1,341	N.M.	N.M.	16,544	(987)	N.M.	N.M.
Other	3,739	2,364	16.4%	N.M.	57,929	18,708	9.2%	N.M.
Total	$ 692,722	$ 368,484			$ 1,361,547	$ 398,455		

	AEGCo Nonregulated				KPCo Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Other	$ 119	$ -	N.M.	N.M.	$ 5,591	$ 153	2.0%	N.M.

2003	AEGCo Regulated		KPCo Regulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.5%	31	3.8%	40-50
Transmission	N.M.	N.M.	1.7%	25-75
Distribution	N.M.	N.M.	3.5%	11-75
Other	16.7%	N.M.	7.1 %	N.M.

TCC

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	$ 817,351	$ 204,426	2.1%	40-71	$ -	$ -	N.M.	N.M.
Distribution	1,476,683	332,143	3.4%	15-62	-	-	N.M.	N.M.
CWIP	129,800	1,147	N.M.	N.M.	-	-	N.M.	N.M.
Other	229,893	97,196	6.5%	N.M.	3,468	1,166	2.9%	N.M.
Total	$ 2,653,727	$ 634,912			$ 3,468	$ 1,166		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	$ 788,371	$ 234,914	2.3%	35-60	$ -	$ -	N.M.	N.M.
Distribution	1,433,380	405,412	3.4%	25-60	-	-	N.M.	N.M.
CWIP	50,612	8,256	N.M.	N.M.	-	-	N.M.	N.M.
Other	219,759	76,644	6.5%	N.M.	3,799	1,545	2.9%	N.M.
Total	$ 2,492,122	$ 725,226			$ 3,799	$ 1,545		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
Production	2.5%	N.M.	2.3%	N.M.
Transmission	2.3%	35-60	2.1%	N.M.
Distribution	3.5%	25-60	N.M.	N.M.
Other	8.1%	N.M.	2.9%	N.M.

TNC

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 288,934	$ 117,963	2.6%	20-49
Transmission	289,029	98,630	3.0%	40-75	-	-	N.M.	N.M.
Distribution	492,878	144,465	3.2%	19-55	-	-	N.M.	N.M.
CWIP	42,929	(327)	N.M.	N.M.	3,495	-	N.M.	N.M.
Other	109,264	60,376	9.7%	N.M.	58,585	57,412	4.9%	N.M.
Total	$ 934,100	$ 303,144			$ 351,014	$ 175,375		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 287,212	$ 110,492	2.6%	20-49
Transmission	281,359	97,389	3.0%	40-75	-	-	N.M.	N.M.
Distribution	474,961	138,925	3.2%	19-55	-	-	N.M.	N.M.
CWIP	20,724	(2,768)	N.M.	N.M.	2,897	-	N.M.	N.M.
Other	115,174	61,895	8.4%	N.M.	123,244	121,837	4.9%	N.M.
Total	$ 892,218	$ 295,441			$ 413,353	$ 232,329		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
Production	N.M.	N.M.	2.6 %	20-49
Transmission	3.1%	40-75	N.M.	N.M.
Distribution	3.3%	19-55	N.M.	N.M.
Other	10.2%	N.M.	4.9 %	N.M.

APCo

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 1,140,438	$ 515,967	2.9%	40-120	$ 1,657,719	$ 748,739	2.9%	40-120
Transmission	1,266,855	481,978	2.2%	35-65	-	-	N.M.	N.M.
Distribution	2,141,153	655,856	3.2%	10-60	-	-	N.M.	N.M.
CWIP	481,579	(4,844)	N.M.	N.M.	166,059	(5,210)	N.M.	N.M.
Other	289,924	119,178	9.3%	N.M.	33,234	13,191	3.2%	N.M.
Total	$ 5,319,949	$ 1,768,135			$ 1,857,012	$ 756,720		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 1,019,851	$ 500,928	2.8%	40-120	$ 1,482,422	$ 728,148	2.8%	40-120
Transmission	1,255,390	458,247	2.2%	35-65	-	-	N.M.	N.M.
Distribution	2,070,377	626,406	3.3%	10-60	-	-	N.M.	N.M.
CWIP	273,987	(29)	N.M.	N.M.	125,129	(2,610)	N.M.	N.M.
Other	302,474	132,130	9.4%	N.M.	33,577	13,197	3.2%	N.M.
Total	$ 4,922,079	$ 1,717,682			$ 1,641,128	$ 738,735		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.2%	40-120	3.2%	40-120
Transmission	2.2%	35-65	N.M.	N.M.
Distribution	3.3%	10-60	N.M.	N.M.
Other	9.3%	N.M.	3.2%	N.M.

CSPCo

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 1,874,652	$ 759,789	3.1%	40-59
Transmission	457,937	192,282	2.3%	33-50	-	-	N.M.	N.M.
Distribution	1,380,722	475,669	3.6%	12-56	-	-	N.M.	N.M.
CWIP	69,800	(3,781)	N.M.	N.M.	59,446	63	N.M.	N.M.
Other	161,205	73,505	10.2%	N.M.	22,891	3,331	N.M.	N.M.
Total	$ 2,069,664	$ 737,675			$ 1,956,989	$ 763,183		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 1,658,552	$ 761,085	2.9%	40-50
Transmission	432,714	186,052	2.3%	33-50	-	-	N.M.	N.M.
Distribution	1,300,252	448,762	3.6%	12-56	-	-	N.M.	N.M.
CWIP	34,631	1,016	N.M.	N.M.	97,112	52	N.M.	N.M.
Other	167,986	74,984	10.3%	N.M.	25,828	3,506	N.M.	N.M.
Total	$ 1,935,583	$ 710,814			$ 1,781,492	$ 764,643		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	N.M.	N.M.	3.0%	40-50
Transmission	2.3%	33-50	N.M.	N.M.
Distribution	3.6%	12-56	N.M.	N.M.
Other	9.9%	N.M.	N.M.	N.M.

2005	I&M Regulated				PSO Regulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 3,128,078	$ 1,901,698	3.8%	40-119	$ 1,072,928	$ 639,256	2.7%	30-57
Transmission	1,028,496	401,024	1.9%	30-65	479,272	153,998	2.1%	40-75
Distribution	1,029,498	335,642	4.1%	12-65	1,140,535	262,763	3.1%	25-65
CWIP	311,080	(1,544)	N.M.	N.M.	90,455	(7,798)	N.M.	N.M.
Other	309,217	79,741	11.7%	N.M.	207,211	127,639	7.4%	N.M.
Total	$ 5,806,369	$ 2,716,561			$ 2,990,401	$ 1,175,858		

	I&M Nonregulated				PSO Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Other	$ 155,913	$ 105,997	3.4%	N.M.	$ 4,594	$ -	N.M.	N.M.

2004	I&M Regulated				PSO Regulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 3,122,883	$ 1,813,130	3.7%	40-119	$ 1,072,022	$ 619,348	2.7%	30-57
Transmission	1,009,551	391,980	1.9%	30-65	468,735	150,799	2.3%	40-75
Distribution	990,826	329,665	4.1%	12-65	1,089,187	260,623	3.3%	25-65
CWIP	163,515	(1,545)	N.M.	N.M.	41,028	(9,899)	N.M.	N.M.
Other	275,627	70,249	11.2%	N.M.	200,044	96,242	7.9%	N.M.
Total	$ 5,562,402	$ 2,603,479			$ 2,871,016	$ 1,117,113		

	I&M Nonregulated				PSO Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Other	$ 155,078	$ 104,643	3.4%	N.M.	$ 4,823	$ 422	N.M.	N.M.

2003	I&M Regulated		PSO Regulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.8%	40-119	2.7%	30-57
Transmission	1.9%	30-65	2.4%	40-75
Distribution	4.2%	12-65	3.4%	25-65
Other	11.8%	N.M.	9.7%	N.M.

OPCo

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 4,278,553	$ 1,876,732	2.8%	35-61
Transmission	1,002,255	403,260	2.3%	27-70	-	-	N.M.	N.M.
Distribution	1,258,518	338,652	3.9%	12-55	-	-	N.M.	N.M.
CWIP	66,103	(1,361)	N.M.	N.M.	624,065	1,494	N.M.	N.M.
Other	234,569	110,743	10.7%	N.M.	59,225	9,379	3.0%	N.M.
Total	$ 2,561,445	$ 851,294			$ 4,961,843	$ 1,887,605		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 4,127,284	$ 1,785,442	2.8%	35-42
Transmission	978,492	396,365	2.3%	27-70	-	-	N.M.	N.M.
Distribution	1,202,550	323,765	4.0%	12-55	-	-	N.M.	N.M.
CWIP	48,732	(1,454)	N.M.	N.M.	192,225	493	N.M.	N.M.
Other	248,748	112,628	10.1%	N.M.	60,740	15,964	3.0%	N.M.
Total	$ 2,478,522	$ 831,304			$ 4,380,249	$ 1,801,899		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	N.M.	N.M.	2.8%	35-42
Transmission	2.3%	27-70	N.M.	N.M.
Distribution	4.0%	12-55	N.M.	N.M.
Other	10.5%	N.M.	3.0%	N.M.

SWEPCo

2005	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 912,044	$ 577,611	3.3%	30-57	$ 748,348	$ 483,743	3.3%	30-57
Transmission	645,297	201,521	2.8%	40-55	-	-	N.M.	N.M.
Distribution	1,153,026	339,258	3.6%	16-65	-	-	N.M.	N.M.
CWIP	81,437	(73)	N.M.	N.M.	22,738	667	N.M.	N.M.
Other	362,572	134,575	7.2%	N.M.	81,177	38,914	N.M.	N.M.
Total	$ 3,154,376	$ 1,252,892			$ 852,263	$ 523,324		

2004	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 916,912	$ 566,513	3.3%	30-57	$ 746,249	$ 470,541	3.3%	30-57
Transmission	632,964	188,455	2.8%	40-55	-	-	N.M.	N.M.
Distribution	1,114,480	318,915	3.6%	16-65	-	-	N.M.	N.M.
CWIP	40,647	6,202	N.M.	N.M.	8,205	1,537	N.M.	N.M.
Other	358,119	126,480	6.9%	N.M.	74,932	32,207	N.M.	N.M.
Total	$ 3,063,122	$ 1,206,565			$ 829,386	$ 504,285		

2003	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.3%	30-57	3.3%	30-57
Transmission	2.8%	40-55	N.M.	N.M.
Distribution	3.6%	16-65	N.M.	N.M.
Other	8.0%	N.M.	N.M.	N.M.

N.M. = Not Meaningful

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 $0.66, $0.65, and $0.41 per ton in 2005, 2004 and 2003, respectively. In 2004, average amortization 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 (ARO)

The Registrant Subsidiaries 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 obligation related to asset retirement. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

In the fourth quarter of 2005, the Registrant Subsidiaries recorded ARO in accordance with FIN 47 related to the removal and disposal of asbestos in general buildings and generating plants (See "FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligation" (FIN 47)" and "Cumulative Effect of Accounting Changes" sections of Note 2).

As of December 31, 2005 and 2004, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $870 million and $791 million, respectively. These assets are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets. As of December 31, 2004, the fair value of TCC's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $143 million. These assets related to the STP nuclear plant, which was sold in 2005. These assets were included in Assets Held for Sale – Texas Generation Plants on TCC's 2004 Consolidated Balance Sheet. Due to the sale, we are no longer responsible for the STP decommissioning liabilities.

The following is a reconciliation of the 2004 and 2005 aggregate carrying amounts of ARO by Registrant Subsidiary:

	ARO at January 1, 2004, Including Held for Sale	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2004, Including Held for Sale
AEGCo (a)	$ 1,126	$ 90	$ -	$ -	$ -	$ 1,216
APCo (a)	21,776	1,740	-	(469)	1,579	24,626
CSPCo (a)	8,740	703	-	(2)	2,144	11,585
I&M (a)(b)	553,219	39,825	-	-	118,725	711,769
OPCo (a)	42,656	3,430	-	-	(480)	45,606
SWEPCo (c)	8,429	1,274	17,658	-	-	27,361
TCC (d)	218,771	16,726	-	-	13,375	248,872

	ARO at January 1, 2005, Including Held for Sale	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2005
AEGCo (a)(e)	$ 1,216	$ 98	$ 56	$ -	$ -	$ 1,370
APCo (a)(e)	24,626	1,928	8,972	(32)	2	35,496
CSPCo (a)(e)	11,585	864	1,981	(9)	3,423	17,844
I&M (a)(b)(e)	711,769	47,368	5,801	-	(26,979)	737,959
KPCo (e)	-	-	1,190	-	-	1,190
OPCo (a)(e)	45,606	3,665	9,513	-	6,773	65,557
PSO (e)	-	-	6,056	-	-	6,056
SWEPCo (a)(c)(e)(f)	27,361	1,491	18,071	(3,449)	(397)	43,077
TCC (d)(e)	248,872	7,549	1,165	(256,421)	-	1,165
TNC (e)	-	-	13,514	-	-	13,514

(a) Includes ARO related to ash ponds.

(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant ($731 million and $711 million at December 31, 2005 and 2004, respectively).

(c) Includes ARO related to Sabine Mining Company and Dolet Hills Lignite Company, LLC.

(d) Includes ARO related to nuclear decommissioning costs for TCC's share of STP which is included in Liabilities Held for Sale – Texas Generation Plants on TCC's 2004 Consolidated Balance Sheet. STP was sold in May 2005 (see Note 10).

(e) Includes ARO related to asbestos removal.

(f) The current portion of SWEPCo's ARO, totaling $2 million, is included in Other in the Current Liabilities section of SWEPCo's 2005 Consolidated Balance Sheet.

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 2005, 2004 and 2003 are as follows:

	2005	2004	2003
		(in millions)	
AEGCo	$ 0.3	$ -	$ -
APCo	16.7	14.7	8.5
CSPCo	3.1	6.1	6.3
I&M	8.8	4.1	8.2
KPCo	0.6	0.5	1.7
OPCo	17.8	6.3	5.0
PSO	1.5	0.6	0.8
SWEPCo	3.6	1.1	1.7
TCC	2.5	1.9	1.1
TNC	1.1	0.6	0.8

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

Fossil fuel inventories are carried at average cost for AEGCo, APCo, I&M, KPCo and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. TNC carries fossil fuel inventories at the lower of cost or market using a LIFO 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 or delivery 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 APCo's 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 company's balance sheet (see "Sale of Receivables - AEP Credit" 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:

	2005	2004	2003
		(in percentage)	
TCC –ERCOT and Centrica			
Percentage of Operating Revenues	29%	72%	55%
Percentage of Accounts Receivable - Customers	7	54	N/A
TNC –ERCOT and Centrica			
Percentage of Operating Revenues	27	57	55
Percentage of Accounts Receivable - Customers	12	59	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 and related chemical and emission allowance consumables are charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. When a fuel cost disallowance becomes probable, the Registrant Subsidiaries adjust their deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4). For TCC & TNC, their deferred fuel balances were included in their True-up Proceedings (see Note 6). See Note 5 for the amount of deferred fuel costs by Registrant Subsidiary. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia and Texas-ERCOT, respectively.

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 customers 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 capped, frozen or suspended for a period of years, fuel costs impact 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) authorized the billing of capped fuel rates on an interim basis until April 1, 2005 and subsequently extended these rates until June 30, 2007. In West Virginia, the fuel clause is suspended indefinitely. See Notes 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 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 ERCOT portion of 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's west zone is short capacity and must purchase physical power to supply retail and wholesale customers. For power purchased under derivative contracts in AEP's west zone where we are short capacity, 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 "Derivatives and Hedging" section of 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 all contracts 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). 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 revenues on a net basis. Unrealized mark-to-market losses and gains are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions, a future cash flow (cash flow hedge) or 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 derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income (Loss) and depending upon the specific nature of the risk being hedged, subsequently reclassified into Revenues or fuel expenses 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 "Fair Value Hedging Strategies" and "Cash Flow Hedging Strategies" section of 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. Such revenue and related expenses are included in Other Nonaffiliated Revenue and Other Operation Expenses, respectively, in the financial statements. Contractually billable expenses not yet billed, 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&M's Cook Plant are deferred and amortized over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's 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 those maintenance costs with their recovery in cost-based regulated revenues. Maintenance costs during refueling outages at the Cook Plant are deferred and amortized over the period between outages in accordance with rate orders in Indiana and Michigan.

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 are 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 amortized over the life of the 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 plants 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 Expense.

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. Beginning July 1, 2003, the Registrant Subsidiaries 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, 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, 2005 and 2004.

Emission Allowances

The Registrant Subsidiaries, except AEG, record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlement received at no cost from the Federal EPA. They follow the inventory model for all allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies for all the Registrant Subsidiaries except CSPCo and OPCo, who reflect allowances in Emission Allowances. Allowances

with expected consumption beyond one year are included in Other Noncurrent Assets-Deferred Charges and Other. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Current Assets-Prepayments and Other for all the Registrant Subsidiaries except CSPCo and OPCo, who reflect allowances in Emission Allowances. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and the Registrant Subsidiaries revenue optimization strategy for their operations.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC 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 permitted 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 net of 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&M's Cook Plant. In 2004, amounts for TCC are included in Assets Held for Sale-Texas Generation Plants for amounts relating to its ownership in STP. 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.

The following is a summary of I&M's nuclear trust fund investments at December 31:

	2005				2004			
($ millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash	$ 21	$ -	$ -	$ 21	$ 20	$ -	$ -	$ 20
Debt Securities	691	7	(7)	691	634	8	(3)	639
Equity Securities	277	148	(3)	422	282	114	(2)	394
Spent Nuclear Fuel and Decommissioning Trusts	$ 989	$ 155	$ (10)	$ 1,134	$ 936	$ 122	$ (5)	$ 1,053

Proceeds from sales of nuclear trust fund investments were $557 million, $863 million and $580 million in 2005, 2004 and 2003, respectively. Purchases of nuclear trust fund investments were $607 million, $901 million and $657 million in 2005, 2004 and 2003, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $4 million, $10 million and $26 million in 2005, 2004 and 2003, respectively. Gross realized losses from the sales of nuclear trust fund investments were $16 million, $17 million and $5 million in 2005, 2004 and 2003, respectively.

The following is a summary of TCC's nuclear trust fund investments at December 31:

	2004			
($ millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Cash	$ 2	$ -	$ -	$ 2
Debt Securities	57	2	(1)	58
Equity Securities	48	35	-	83
Decommissioning Trusts Included in Assets Held for Sale	$ 107	$ 37	$ (1)	$ 143

Proceeds from sales of nuclear trust fund investments were $150 million, $87 million and $41 million in 2005, 2004 and 2003, respectively. Purchases of nuclear trust fund investments were $154 million, $100 million and $51 million in 2005, 2004 and 2003, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $8.6 million, $2.5 million and $0.5 million in 2005, 2004 and 2003, respectively. Gross realized losses from the sales of nuclear trust fund investments were $1.8 million, $0.9 million and $1.4 million in 2005, 2004 and 2003, respectively.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2005 for I&M is as follows:

	Fair Value (in millions)
Within 1 year	$ 17
1 year – 5 years	298
5 years – 10 years	173
After 10 years	203
	$ 691

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 common shareholder's equity section. Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of December 31, 2005 and 2004 is shown in the following table.

Components	December 31, 2005	December 31, 2004
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (16,421)	$ (9,324)
CSPCo	(859)	1,393
I&M	(3,467)	(4,076)
KPCo	(194)	813
OPCo	755	1,241
PSO	(1,112)	400
SWEPCo	(5,852)	(820)
TCC	(224)	657
TNC	(111)	285
Minimum Pension Liability:		
APCo	$ (189)	$ (72,348)
CSPCo	(21)	(62,209)
I&M	(102)	(41,175)
KPCo	(29)	(9,588)
OPCo	-	(75,505)
PSO	(152)	(325)
SWEPCo	(277)	(360)
TCC	(928)	(4,816)
TNC	(393)	(413)

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.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

The Registrant Subsidiaries' Statements of Operations were converted from a utility format presentation where only regulated cost-of-service items were reflected in Operating Income to a commercial format presentation where nonutility items are reflected as components of Operating Income. Also, in the Balance Sheets under the commercial format we include nonutility property in Other Property, Plant and Equipment.

In addition, in the Registrant Subsidiaries' Statements of Operations, we reclassified the consumption of emission allowances and consumption of chemicals used in the generation of power from Other Operation to Fuel and Other Consumables Used for Electric Generation as follows:

	Year Ended December 31, 2004	2003
	(in thousands)	
AEGCo	$ -	$ -
APCo	12,233	10,320
CSPCo	19,736	17,308
I&M	6,693	4,505
KPCo	4,425	4,826
OPCo	68,237	57,927
PSO	24	-
SWEPCo	826	-
TCC	1,213	-
TNC	5	-

The Registrant Subsidiaries also reclassified the net gain or loss on the sales of emission allowances from Other Operation to Revenues. These reclassifications were not material for 2004 or 2003.

In the Balance Sheets for the AEP West companies, we netted certain Accounts Receivable - Customers and Accounts Payable – General consistent with the netting performed by the AEP East companies and to more accurately reflect the net positions with risk management activity counterparties. The decrease (increase) in Accounts Receivable – Customers and in Accounts Payable - General were as follows:

	December 31, 2004
	(in thousands)
PSO	$ 1,993
SWEPCo	(383)
TCC	17,470
TNC	8,367

These revisions had no impact on our previously reported results of operations or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS 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 that we have determined relate to our operations.

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, "Accounting for Stock Issued to Employees." A cumulative effect of a change in accounting principle will be recorded for the effect of initially applying the statement.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required 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 is based on the grant-date fair value of the equity award. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that do not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle should be recognized in the period of the accounting change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. SFAS 154 was effective beginning January 1, 2006 and will be applied as necessary.

FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

The Registrant Subsidiaries adopted FIN 47 during the fourth quarter of 2005. In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143 "Accounting for Asset Retirement Obligations." FIN 47 clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

The Registrant Subsidiaries completed a review of their FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In the fourth quarter of 2005, the Registrant Subsidiaries recorded conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to regulated operations was generally charged to regulatory liability. The Registrant Subsidiaries with nonregulated operations recorded an unfavorable cumulative effect related to asbestos removal for those operations.

The following table shows the liability for conditional ARO and cumulative effect recorded for FIN 47 by Registrant Subsidiary:

	Liability Recorded	Cumulative Effect	
		Pretax	Net of Tax
		(in thousands)	
AEGCo	$ 56	$ -	$ -
APCo	8,972	(3,470)	(2,256)
CSPCo	1,981	(1,292)	(839)
I&M	5,801	-	-
KPCo	1,190	-	-
OPCo	9,513	(7,039)	(4,575)
PSO	6,056	-	-
SWEPCo	6,702	(1,926)	(1,252)
TCC	1,165	-	-
TNC	13,514	(13,034)	(8,472)

The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which they have assets. Generally, such easements are perpetual and require only the retirement and removal of the Registrant Subsidiaries' assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use the facilities indefinitely. The retirement obligations would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements.

Pro forma net income is not presented for the years ended December 31, 2004 and 2003 because the pro forma application of FIN 47 would result in pro forma net income not materially different from the actual amounts reported during those periods.

The following is a summary by Registrant Subsidiary of the pro forma liability for conditional ARO which has been calculated as if FIN 47 had been adopted as of the beginning of each period presented:

	December 31,	
	2004	2003
	(in thousands)	
AEGCo	$ 53	$ 50
APCo	8,434	7,928
CSPCo	1,862	1,750
I&M	5,453	5,126
KPCo	1,119	1,052
OPCo	8,943	8,407
PSO	5,693	5,352
SWEPCo	6,757	6,351
TCC	1,085	1,020
TNC	12,704	11,942

See "Accounting for Asset Retirement Obligations (ARO)" section of Note 1 for further discussion.

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 cash flows in determining whether cash flows have been or will be eliminated and also what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. We applied this issue to components we disposed or classified as held for sale.

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

This issue focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions" if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges fininished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on our financial statements.

Future Accounting Changes

The FASB's 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, fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

EXTRAORDINARY ITEMS

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on those deliberations and oral decisions, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million ($225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" (SFAS 101) and is reflected in TCC's Consolidated Statements of Operations as Extraordinary Loss on Stranded Cost Recovery, Net of Tax (see "Texas True-up Proceedings" section of Note 6).

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, TCC's stranded generation plant costs regulatory asset was reduced by $238 million based on a PUCT adjustment in a nonaffiliated utility's true-up order (see "Wholesale Capacity Auction True-up and Stranded Plant Cost" section of Note 6). These net adjustments were recorded as an extraordinary item of $121 million net of tax in accordance with SFAS 101 and are reflected in TCC's Consolidated Statements of Operations as Extraordinary Loss on Stranded Cost Recovery, Net of Tax.

In 2003, an extraordinary item of $177 thousand, net of tax of $95 thousand, 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.

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. The Registrant Subsidiaries except PSO and AEGCo have recorded net of tax charges against net income in Cumulative Effect of Accounting Changes on their financial statements in 2003. These amounts are recognized as the positions settle.

Asset Retirement Obligations

In 2003, certain Registrant Subsidiaries recorded a cumulative effect of accounting change for ARO in accordance with SFAS 143.

In the fourth quarter of 2005, certain Registrant Subsidiaries recorded a net of tax loss as a cumulative effect of accounting change for ARO in accordance with FIN 47.

The following is a summary by Registrant Subsidiary of the cumulative effect of changes in accounting principles recorded in 2005 and 2003 for the adoptions of FIN 47, SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	2005		2003			
	FIN 47 Cumulative Effect		SFAS 143 Cumulative Effect		EITF 02-3 Cumulative Effect	
			(in millions)			
	Pretax Income (Loss)	Net of Tax Income (Loss)	Pretax Income (Loss)	Net of Tax Income (Loss)	Pretax Income (Loss)	Net of Tax Income (Loss)
APCo	$ (3.5)	$ (2.3)	$ 128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	(1.3)	(0.8)	49.0	29.3	(3.1)	(2.0)
I&M	-	-	-	-	(4.9)	(3.2)
KPCo	-	-	-	-	(1.7)	(1.1)
OPCo	(7.0)	(4.6)	213.6	127.3	(4.2)	(2.7)
SWEPCo	(1.9)	(1.3)	13.0	8.4	0.2	0.1
TCC	-	-	-	-	0.2	0.1
TNC	(13.0)	(8.5)	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

SWEPCo's acquired intangible asset subject to amortization is $15.8 million at December 31, 2005 and $18.8 million at December 31, 2004, net of accumulated amortization and is included in Deferred Charges and Other on SWEPCo's Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization are:

		December 31, 2005		December 31, 2004	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced royalties	10	$ 29.4	$ 13.6	$ 29.4	$ 10.6

Amortization of the intangible asset was $3 million per year for 2005, 2004 and 2003. SWEPCo's estimated total amortization is $3 million per year for 2006 through 2010 and $1 million in 2011.

4. RATE MATTERS

APCo Virginia Environmental and Reliability Costs – Affecting APCo

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request included incurred and projected costs from July 1, 2004 through June 30, 2006 which

relate to (i) environmental controls on coal-fired generators to meet the first phase of the final Clean Air Interstate Rule and Clean Air Mercury Rule issued in 2005, (ii) the Wyoming-Jacksons Ferry 765 kilovolt transmission line construction and (iii) other incremental T&D system reliability work.

In the filing, APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. In October 2005, the Virginia SCC denied APCo's request to place the proposed cost recovery surcharge in effect, on an interim basis subject to refund. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the public hearing in this case which began on February 27, 2006.

The Virginia SCC also ruled that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, the order permitted APCo to update its request to reflect additional actual costs and/or present additional evidence. Accordingly, in November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery of E&R costs to $21 million of actual incremental E&R costs incurred during the period July 1, 2004 through September 30, 2005.

Through December 31, 2005, APCo has deferred $24 million of recorded E&R costs. It has not yet recorded $4 million of such costs which represent equity carrying costs that are not recognized until collected through regulated rates. In addition, APCo has reversed $5 million of AFUDC/interest capitalized through December 31, 2005 related to incremental E&R capital investments that would have been duplicative of a portion of the deferred E&R carrying costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to include $20 million of incremental E&R costs in its electric rates. The staff also recommended the disallowance of the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that have been established as a regulatory asset as of December 31, 2005. We believe the staff's position is contrary to the Virginia SCC's October 2005 order, which denied APCo's request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incurred incremental E&R costs after the commission examines and approves such costs. If the Virginia SCC denies recovery of any of APCo's deferred E&R costs, the denial could adversely impact future results of operations and cash flows. Hearings began on February 27, 2006.

APCo West Virginia Rate Case – Affecting APCo

In August 2005, APCo collectively filed an application with the WVPSC seeking an initial increase in their retail rates of approximately $77 million. The initial increase requests approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism which accounts for $65 million of the initial increase. The request also seeks approval to implement a system reliability tracker which accounts for $9 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins and transmission items.

In addition, APCo requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining proposed supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively.

APCo has a regulatory liability of $52 million for pre-suspension, over-recovered ENEC costs. APCo proposed to apply this $52 million, along with a carrying cost, as a reduction to any future under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism.

In January 2006, APCo submitted supplemental testimony addressing the Ceredo Generating Station acquisition (see "Acquisitions" section of Note 10) and certain revisions to their filing. The supplemental filing revised the initial requested increase of $77 million downward to $69 million. APCo revised the supplemental increases downward to $43 million, $8 million and $36 million, effective on January 1, 2007, 2008 and 2009, respectively.

In January 2006, APCo, WPCo and the WVPSC staff filed a joint motion requesting a change in the procedural schedule. The motion, as modified, requests that hearings begin in April 2006, new rates go into effect on July 28, 2006 and deferral accounting for over - or under – recovery of the ENEC costs begins July 1, 2006. In response to that motion, the WVPSC approved the proposed schedule including the commencement date for the ENEC deferral accounting. At this time, management cannot predict the ultimate effect on APCo's future revenues, results of operations and cash flows of APCo's base rate increase proceeding in West Virginia.

I&M Indiana Settlement Agreement – Affecting I&M

In 2003, I&M's fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain parties to the negotiations reached a settlement. The IURC approved the settlement agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate. Total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor was adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at the Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate). If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total cumulative actual fuel costs (except during a Cook Plant outage of greater than 60 days) are less than the cap prices, the savings will be credited to customers over the next two fuel adjustment clause filings. Cumulative net fuel costs in excess of the capped prices cannot be recovered. If the Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

I&M experienced a cumulative under-recovery of fuel costs for the period March 2004 through December 2005 of $12 million. Since I&M expects that its cumulative fuel costs through the end of the fuel cap period will exceed the capped fuel rates, I&M recorded $9 million and $3 million of under-recoveries as fuel expense in 2005 and 2004, respectively. If future fuel costs per KWH through June 30, 2007 continue to exceed the caps, future results of operations and cash flows would be adversely affected.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

I&M Depreciation Study Filing – Affecting I&M

In December 2005, I&M filed a petition with the IURC which seeks authorization effective January 1, 2006 to revise the book depreciation rates applicable to its electric utility plant in service. This petition is not a request for a change in customers' electric service rates. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Nuclear Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. If approved, the book depreciation expense reduction would increase earnings, but would not impact cash flows. Hearings are scheduled to begin in May 2006. When approved by the IURC, I&M will prospectively revise its book depreciation rates and, if appropriate, currently adjust its book depreciation expense to the approved effective date.

KPCo Rate Filing – Affecting KPCo

In September 2005, KPCo filed a request with the Kentucky Public Service Commission (KPSC) to increase base rates by approximately $65 million to recover increasing costs. The major components of the rate increase included a return on common equity of 11.5% or $26 million, the impact of reduced through-and-out transmission revenues of $10 million, recovery of additional AEP Power Pool capacity costs of $9 million, additional reliability spending of $7 million and increased depreciation expense of $5 million. In February 2006, KPCo executed and submitted a settlement agreement to the KPSC for its approval. The major terms of the agreement are as follows: KPCo will receive a $41 million increase in revenues effective March 30, 2006, KPCo will retain its existing environmental surcharge tariff and KPCo will continue to include in the calculation of its annual depreciation expense the depreciation rates currently approved and utilized as a result of KPCo's 1991 rate case. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and for AFUDC purposes. The KPSC has not approved the settlement agreement and therefore, management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power and its Possible Impact on AEP East Companies – Affecting PSO and AEP East companies

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 offered to collect those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs, future results of operations and cash flows would be adversely affected.

In the review of PSO's 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between and among AEP East companies and AEP West companies and specifically PSO was inconsistent with the FERC-approved Operating Agreement and SIA and that the AEP West companies should have been allocated greater margins. The parties objected to the inclusion of mark-to-market amounts in developing the allocation base. In addition, an intervenor recommended that $9 million of the $42 million related to the 2002 reallocation not be recovered from Oklahoma retail customers because that amount was not refunded by PSO's affiliated AEP West companies to their wholesale customers outside of Oklahoma.

The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002. In July 2005, the OCC staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East companies and AEP West companies. Their overall recommendations would result in an increase in off-system sales margins allocated to PSO and thus, a reduction in its recoverable fuel costs through December 2004 in a range of $38 million to $47 million.

In January 2006, the OCC staff and intervenors issued supplemental testimony proposing that the OCC offset the under-recovered fuel clause deferral inclusive of the $42 million with off-system sales margins of $27 million to $37 million through December 2004. The OCC staff also recommended a disallowance of $6 million. Hearings were held in early February 2006 to address the issues. PSO does not agree with the intervenors' and the OCC staff's recommendations and will defend vigorously its position.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. Intervenors appealed the ALJ ruling to the OCC. The OCC has not ruled on the intervenors' appeal or the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from deciding this same allocation issue in Texas. The Court agreed that the FERC had jurisdiction over the SIA and that the sole remedy is at the FERC.

If the OCC decides to provide for additional off-system sales margins, it could adversely affect future results of operations and cash flows. However, if the position taken by the federal court in Texas is applied to PSO's case, the OCC would be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins due to a lack of jurisdiction. The OCC or another party could file a complaint at the FERC which could

ultimately be successful, and which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To-date there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings and future FERC proceedings, if any, on future results of operations, cash flows and financial condition.

In April 2005, the OCC heard arguments from intervenors that requested the OCC conduct a prudence review of PSO's fuel and purchased power practices for 2003. In June 2005, the OCC asked its staff to conduct that review. The OCC staff is scheduled to file its testimony in March 2006 and the hearings are scheduled for May 2006.

PSO 2005 Fuel Factor Filing – Affecting PSO

In November 2005, PSO submitted to the OCC staff an interim adjustment to PSO's annual fuel factors. PSO's new factors were based on increased natural gas and purchased power market prices, as well as past under-recovered fuel costs. PSO implemented the new fuel factors in its December 2005 billing. The new fuel factors are estimated to increase 2006 revenues by approximately $349 million. At December 31, 2005, PSO had a deferred under-recovered fuel balance of $109 million, which includes interest and the $42 million discussed above in "PSO Fuel and Purchased Power and its Possible Impact on AEP East companies." This fuel factor adjustment will increase cash flows without impacting PSO's results of operations as any over or under-recovery of fuel cost will be deferred as a regulatory liability or regulatory asset.

PSO Rate Review – Affecting PSO

PSO was involved in an OCC staff-initiated base rate review, which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates by $41 million, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. The settlement provided for a $7 million annual base revenue reduction offset by a $6 million reduction in annual depreciation expense and recovery through fuel revenues of certain transmission expenses previously recovered in base rates. In addition, the settlement eliminated a $9 million annual merger savings rate reduction rider at the end of December 2005. The settlement also provided for recovery, over 24 months, of $9 million of deferred fuel costs associated with a renegotiated coal transportation contract and the continuation of a $12 million vegetation management rider, both of which are earnings neutral. Finally, the settlement stipulated that PSO may not file for a base rate increase before April 1, 2006. The OCC approved the stipulation in May 2005 and new base rates were implemented in June 2005.

PSO 2005 Vegetation Management Filing – Affecting PSO

In June 2005, PSO filed testimony to adjust its vegetation management rate rider from the OCC-approved $12 million to $27 million. In November 2005, the OCC issued a final order approving an increase to the cap on the PSO vegetation management rider to $24 million, which is in addition to the $6 million vegetation management expenses currently included in base rates. The final order also provided for the recovery of carrying and other costs associated with converting overhead distribution lines to underground lines. PSO does not anticipate any material effect on income for the incremental costs associated with the increased cap as the incremental costs will be deferred and expensed in the future when the rate rider revenues are recognized.

SWEPCo PUCT Staff Review of Earnings – Affecting SWEPCo

In October 2005, the staff of the PUCT reported results of its review of SWEPCo's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff has engaged SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. Management is unable to predict the outcome of this initial report on SWEPCo's future revenues, results of operations, cash flows and financial condition.

SWEPCo Louisiana Fuel Issues – Affecting SWEPCo

In November 2005, the Louisiana Public Service Commission (LPSC) amended an inquiry into the operation of the fuel adjustment clause recovery mechanisms of other Louisiana electric utilities to include SWEPCo. The inquiry was initiated to determine whether utilities had purchased fuel and power at the lowest possible price and whether suppliers offered competitive prices for fuel and purchased power during the period of January 1, 2005 through October 31, 2005.

In December 2005, the LPSC initiated a new audit of SWEPCo's historical fuel costs which will cover the years 2003 and 2004, pursuant to the LPSC's general order requiring biennial fuel reviews. Management cannot predict the outcome of these audits/reviews, but believes that SWEPCo's fuel and purchased power procurement practices were prudent and costs were properly incurred. If the LPSC disagrees and disallows fuel or purchased power costs incurred by SWEPCo, it would have an adverse effect on SWEPCo's 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 LPSC's merger order also provided that SWEPCo's base rates were capped 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 SWEPCo's rates should not be reduced. Subsequently, direct testimony was filed on behalf of the LPSC recommending a $15 million reduction in SWEPCo's Louisiana jurisdictional base rates. SWEPCo's rebuttal testimony was filed in January 2005 and subsequent deposition proceedings are in process. 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 SWEPCo's future results of operations and cash flows.

TCC Rate Case – Affecting TCC

In August 2005, the PUCT issued an order in a base rate proceeding initiated in 2003 by a Texas municipality. The order reduced TCC's annual base rates by $9 million. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. Tariffs were approved and the rate change was implemented effective September 6, 2005. TCC and other parties have appealed this proceeding to the Texas District Court. No schedule has been set for hearing the appeals. Management cannot predict the ultimate outcome of these appeals. Also, in the third quarter of 2005, TCC reclassified $126 million of asset removal costs from Accumulated Depreciation and Amortization to Regulatory Liabilities and Deferred Investment Tax Credits on TCC's Consolidated Balance Sheets based on a depreciation study prepared by TCC and approved by the PUCT.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU; 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 of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court on the loss of load issue, but otherwise affirmed its decision. The amount of unaccounted-for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million. AEP's 2005 pretax earnings were adversely affected by $3 million because of this decision. In a decision on rehearing in February 2006, the Texas Court of Appeals no longer is directing on remand that the unaccounted for energy issue be reconsidered solely based on the existing record. The prior ruling would have prevented the PUCT from considering additional evidence on the $3 million adjustment. Management cannot predict the outcome of further appeals but a reversal of the favorable court of appeals decision regarding the loss of load issue would adversely impact TCC's and TNC's results of operations and cash flows.

RTO Formation/Integration – Affecting APCo, CSPCo, I&M, KPCo and OPCo

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs and carrying costs incurred to originally form a new RTO (the Alliance) and subsequently to integrate into an existing RTO (PJM). In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The formation and integration costs included in AEP's application by company follows:

Company	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)	
APCo	$ 4.8	$ 5.1
CSPCo	2.0	2.2
I&M	3.8	3.8
KPCo	1.1	1.1
OPCo	5.5	5.7

The FERC approved AEP's application and in January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years consistent with a March 2005 requested rate recovery period discussed below. The total amortization related to such costs was $5 million in 2005. The AEP East companies did not record $5 million and $4 million of equity carrying costs in 2005 and 2004, respectively, which are not recognized until collected.

The AEP East companies' deferred unamortized RTO formation/integration costs were as follows:

	December 31, 2005		December 31, 2004	
	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)			
APCo	$ 4.1	$ 4.9	$ 4.7	$ 4.7
CSPCo	1.7	1.9	2.0	1.8
I&M	3.2	3.7	3.5	3.8
KPCo	1.0	1.1	1.0	1.2
OPCo	4.7	5.1	5.3	5.3

In March 2005, AEP and two other utilities jointly filed a request with the FERC to recover their deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. In May 2005, the FERC issued an order denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a compliance filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the compliance filing in May 2005. In June 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). In October 2005, the FERC granted AEP's June 2005 rehearing request and set the following two issues for settlement discussions and, if necessary, for hearing: (i) whether the PJM OATT is unjust and unreasonable without PJM region-wide recovery of PJM-billed integration costs and (ii) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. Also, the FERC, in its order, dismissed the May 2005 compliance filing as moot. Settlement discussions are still underway, and a result that would collect a portion of the costs in other PJM zones is likely, though not yet assured.

In March 2005, AEP also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed below in the "AEP East Transmission Requirement and Rates" section). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of our deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs).

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM OATT to recover the amount of deferred RTO formation costs to be amortized, determined to be $2 million per year. The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In a December 2005 order, the Public Utilities Commission of Ohio (PUCO) approved recovery of the amortization of RTO Formation/Integration Costs through a Transmission Cost Recovery Rider (TCRR). In Kentucky and West Virginia, filings have been made to recover the amortization of these costs (see "KPCo Rate Filing" section of this Note). The Indiana service territory of I&M is subject to a rate freeze until June 2007, so recovery will be delayed until the freeze ends.

Until all the AEP East companies can adjust their retail rates to recover the amortization of both RTO related deferred costs, their results of operations and cash flows will be adversely affected by the amortizations. The proposed FERC settlement would allow and establish a reasonable carrying charge for the deferred costs. If the FERC or any state regulatory authority was to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs, it would have an adverse impact on the AEP East companies' future results of operations and cash flows. If the FERC approves a carrying charge rate that is lower than the carrying charge recognized to date, it could have an adverse effect on the AEP East companies' future results of operations and cash flows.

Transmission Rate Proceedings at the FERC - Affecting APCo, CSPCo, I&M, KPCo and OPCo

FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue

In July 2003, the FERC issued an order directing PJM and 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).

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 elimination of the T&O charges for transactions between the two RTOs reduces the transmission service revenues collected by the RTOs and thereby, reduces the revenues received by transmission owners, including the AEP East companies, under the RTOs' revenue distribution protocols.

As a result of settlement negotiations in early 2004, the effective date of the SECA transition was delayed by the FERC. The delay was to give parties an opportunity to create a new regional rate regime. When the parties were unable to agree on a single regional rate proposal, the FERC ordered the two-year SECA transition period shortened to sixteen months, effective on December 1, 2004, continuing through March 31, 2006. The FERC has set SECA rate issues for hearing and indicated that the SECA rates are being recovered subject to refund or surcharge. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. At this time, management is unable to determine the probable outcome of the FERC's SECA rate proceeding and its impact on the AEP East companies' future results of operations and cash flows. The AEP East companies recognized net SECA revenues as follows:

	2005	December 2004
	(in millions)	
APCo	$ 41.0	$ 3.5
CSPCo	22.3	2.0
I&M	23.7	2.3
KPCo	9.7	0.8
OPCo	30.8	2.8

AEP East Transmission Revenue Requirement and Rates

In the March 2005 FERC filing discussed in the "RTO Formation/Integration Costs" section above, AEP proposed a two-step increase in the revenue requirements and rates for transmission service, and certain ancillary services in the AEP zone of PJM. The customers receiving these services are the AEP East companies, municipal and cooperative wholesale entities, and retail choice customers with load delivery points in the AEP zone of PJM. In December 2005, the FERC approved an uncontested settlement allowing our wholesale transmission rates to increase in three steps: first, beginning November 1, 2005, second, beginning April 1, 2006 when the SECA revenues are expected to be eliminated and third, on the later of August 1, 2006 or the first day of the month following the date when AEP's Wyoming-Jacksons Ferry transmission line enters service, currently expected to occur in June 2006.

PJM Regional Transmission Rate Proceeding

In a separate proceeding, at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC.

This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway. Under the Highway/Byway rate design proposed by AEP and AP, the cost of all transmission facilities in the PJM region operated at a voltage of 345 kilovolt (kV) or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's rate design which reflects the cost of the facilities in the corporate zone in which the transmission facilities are owned (License Plate Rate). The AEP/AP Highway/Byway design would result in incremental net revenues of approximately $125 million per year for the AEP East transmission-owning companies.

A competing Highway/Byway proposal filed by others would also produce net revenues to the AEP East transmission-owning companies, but at a much lower level. Both proposals are being challenged by a majority of transmission owners in the PJM region who favor continuation of the PJM License Plate Rate design. A group of LSEs has also made a proposal that would include 500 kV and higher existing facilities, and some facilities at lower voltages in the highway rate.

In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design. The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal. The case is scheduled for hearing in April 2006. AEP management cannot at this time estimate the outcome of the proceeding; however, adoption of any of the new proposals would have a positive effect on AEP revenues, compared to the License Plate Rates that will otherwise prevail beginning April 1, 2006 when the transitional SECA rates expire.

As of December 31, 2005, SECA transition rates have not fully compensated the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone will not be sufficient to replace the SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues will require cost recovery through retail rate proceedings. Rate requests are pending in Kentucky and West Virginia that address the reduction in FERC transmission revenues, (see "KPCo Rate Filing" section of this Note). In February 2006, CSPCo and OPCo filed with the PUCO to increase their transmission rates to reflect the loss of their share of SECA revenues. Management is unable to predict when and if the effect of the loss of transmission revenues will be recoverable on a timely basis in all of the AEP East state retail jurisdictions and from wholesale LSEs within the PJM region.

The AEP East companies' future results of operations, cash flows and financial condition would be adversely affected if:

- the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or
- the newly approved AEP zonal transmission rates are not sufficient to replace the lost T&O/SECA revenues, or
- the FERC's review of our current SECA rates results in a rate reduction which is subject to refund, or
- any increase in the AEP East companies' transmission costs from the loss of transmission revenues are not fully recovered in retail rates on a timely basis, or
- the FERC does not approve a new regional rate within PJM.

FERC Market Power Mitigation – Affecting AEP East Companies 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 applicant's minimum load. The FERC also initiated a rulemaking to consider whether the FERC's 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.

In a December 2004 order, the 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, the 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. In February 2005, although management continued to believe the AEP System did not possess market power in SPP, the AEP West companies filed a response and proposed tariff changes to address the FERC's 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.

In July 2005, the FERC accepted for filing the amended tariffs effective March 6, 2005 and set for hearing three aspects of the proposed tariffs. Two parties intervened in the proceeding protesting the proposed cost-based tariffs. In October 2005, all parties and the FERC staff entered into a settlement agreement adopting AEP's proposed tariffs with minor modifications to the rates in consideration of certain long-term power supply arrangements entered into between AEP and the intervenors. In November 2005, the FERC settlement judge issued a certification of uncontested settlement recommending that the settlement agreement be adopted with minor additional provisions to AEP's tariff to bring such tariff into compliance with existing FERC policy. The settlement certification was accepted by the FERC in January 2006.

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 from the FERC's and PJM's market power analysis cannot be determined. Since the cost caps apply only to wholesale loads within AEP's control area inside SPP and these entities are not often in the market for additional power, management does not expect a significant adverse impact from the FERC's actions to-date.

Allocation Agreement between AEP East Companies and AEP West Companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. The current allocation methodology was established at the time of the AEP-CSW merger and, consistent with the terms of the SIA, in November 2005, AEP filed a proposed allocation methodology to be used in 2006 and beyond. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of the AEP West companies. Previously, the SIA allocation provided for a different method of sharing of all such margins between both AEP East companies and AEP West companies. The allocation ultimately approved by the FERC may differ from the one proposed. AEP companies requested that the new methodology be effective on a prospective basis after the FERC's order. The impact on future results of operations and cash flows will depend upon the methodology approved by the FERC, the level of future margins by region and the status of cost recovery mechanisms by state. Total trading and marketing margins are unaffected by the allocation methodology. However, because trading and marketing activities are not treated the same for ratemaking purposes in each state retail jurisdiction and the timing of inclusion of the margins in rates may differ, the AEP East companies' and AEP West companies' results of operations and cash flows could be affected. Management is unable to predict the ultimate effect of this filing on the AEP East companies and AEP West companies' future results of operations and cash flows.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items at December 31:

	AEGCo			APCo		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$ 337,544	$ 343,415	Various Periods (a)
Transition Regulatory Assets – Virginia				21,223	25,467	Up to 5 Years (a)
Unamortized Loss on Reacquired Debt	$ 4,258	$ 4,496	20 Years (b)	17,652	18,157	Up to 27 Years (b)
Other	1,314	1,117	Various Periods (a)	80,875	36,368	Various Periods (a)
Total Noncurrent Regulatory Assets	$ 5,572	$ 5,613		$ 457,294	$ 423,407	
Current Regulatory Assets – Under-recovered Fuel Costs – Virginia				$ 30,697	$ -	1 Year (b)
Regulatory Liabilities:						
Asset Removal Costs	$ 27,640	$ 25,428	(d)	$ 86,315	$ 95,763	(d)
Deferred Investment Tax Credits	42,718	46,250	Up to 17 Years (a)	25,723	30,382	Up to 15 Years (c)
SFAS 109 Regulatory Liability, Net	12,331	12,852	Various Periods (a)			
Over-recovery of Fuel Costs – West Virginia				52,399	52,071	(a)
Other				36,793	23,270	Various Periods (a)
Total Noncurrent Regulatory Liabilities	$ 82,689	$ 84,530		$ 201,230	$ 201,486	

(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 cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

	CSPCo			I&M		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 17,723	$ 16,481	Various Periods (a)	$ 118,743	$ 147,167	Various Periods (a)
Transition Regulatory Assets	144,868	156,676	Up to 3 Years (a)			
Other	69,008	38,846	Various Periods (a)	103,943	103,923	Various Periods (b)
Total Noncurrent Regulatory Assets	$ 231,599	$ 212,003		$ 222,686	$ 251,090	
Regulatory Liabilities:						
Asset Removal Costs	$ 117,942	$ 103,104	(c)	$ 280,819	$ 280,054	(c)
Deferred Investment Tax Credits	25,215	27,933	Up to 15 Years (a)	75,077	82,802	Up to 17 Years (a)
Excess ARO for Nuclear Decommissioning				271,318	245,175	(d)
Other	22,187	-	Various Periods (b)	82,801	69,229	Various Periods (b)
Total Noncurrent Regulatory Liabilities	$ 165,344	$ 131,037		$ 710,015	$ 677,260	

(a) Amount does not earn a return.
(b) A portion of the 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 and lowers plant investment reducing overall return.
(d) 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		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 96,578	$ 103,849	Various Periods (a)	$ 159,742	$ 169,866	Various Periods (a)
Transition Regulatory Assets				139,632	225,273	2 years (a)
Other	20,854	14,558	Various Periods (b)	98,633	33,235	Various Periods (b)
Total Noncurrent Regulatory Assets	$ 117,432	$ 118,407		$ 398,007	$ 428,374	
Regulatory Liabilities:						
Asset Removal Costs	$ 30,291	$ 28,232	(c)	$ 110,098	$ 102,875	(c)
Deferred Investment Tax Credits	5,500	6,722	Up to 15 Years (a)	9,416	12,539	Up to 15 Years (a)
Other	21,003	13,040	Various Periods (b)	48,978	-	Various Periods (b)
Total Noncurrent Regulatory Liabilities	$ 56,794	$ 47,994		$ 168,492	$ 115,414	

(a) Amount does not earn a return.
(b) A portion of the amount effectively earns a return.
(c) The liability for removal cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

	PSO			SWEPCo		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ -	$ -		$ 38,793	$ 18,000	Various Periods (b)
Unrealized Loss on Forward Commitments	18,279	4,730		13,922	4,032	
Unamortized Loss on Reacquired Debt	12,456	14,705	Up to 10 Years (b)	17,973	20,765	Up to 38 Years (b)
Other	19,988	12,516	Various Periods (d)	11,088	12,318	Various Periods (c)
Total Noncurrent Regulatory Assets	$ 50,723	$ 31,951		$ 81,776	$ 55,115	
Current Regulatory Asset - Under-recovered Fuel Costs	$ 108,732	$ 366	1 Year (a)	$ 51,387	$ 4,844	1 Year (a)
Regulatory Liabilities:						
Asset Removal Costs	$ 212,346	$ 220,298	(e)	$ 255,920	$ 249,892	(e)
Deferred Investment Tax Credits	27,273	28,620	Up to 24 Years (d)	31,246	35,539	Up to 12 Years (d)
SFAS 109 Regulatory Liability, Net	12,089	21,963	Various Periods (b)			
Other	32,932	19,676	Various Periods (d)	32,900	24,487	Various Periods (c)
Total Noncurrent Regulatory Liabilities	$ 284,640	$ 290,557		$ 320,066	$ 309,918	

(a) Over/Under-recovered fuel for SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts for SWEPCo do earn a return. PSO fuel balances began earning a return in June 2005.
(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 cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

	TCC			TNC		
	2005	2004	Recovery/ Refund Period	2005	2004	Recovery/ Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$ 20,616	$ 15,236	Various Periods (a)			
Designated for Securitization	1,435,597	1,361,299	(b)			
Wholesale Capacity Auction True-up	76,464	559,973	(c)			
Refunded Excess Earnings	55,461	-	(c)			
Other	100,649	125,470	Various Periods (e)	$ 9,787	$ 12,023	Various Periods (e)
Total Noncurrent Regulatory Assets	$ 1,688,787	$ 2,061,978		$ 9,787	$ 12,023	
Regulatory Liabilities:						
Asset Removal Costs	$ 231,990	$ 102,624	(f)	$ 82,639	$ 81,143	(f)
Deferred Investment Tax Credits	105,134	107,743	Up to 23 Years (d)	17,427	18,698	Up to 17 Years (d)
Over-recovery of Fuel Costs	177,198	211,526	(c)	4,915	3,920	(c)
Retail Clawback	61,384	61,384	(c)	13,924	13,924	(c)
SFAS 109 Regulatory Liability, Net				6,828	8,500	Various Periods (a)
Other	76,437	76,653	Various Periods (e)	13,999	14,589	Various Periods (e)
Total Noncurrent Regulatory Liabilities	$ 652,143	$ 559,930		$ 139,732	$ 140,774	

(a) Amount earns a return.
(b) Amount includes a carrying cost, was included in TCC's 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. See "Texas Restructuring" section of Note 6.
(c) See "Texas Restructuring" and "Carrying Costs on Net True-up Regulatory Assets" sections of Note 6 for discussion of carrying costs. Amounts were included in TCC's and TNC's True-up Proceedings for future recovery/refund over a time period to be determined in future PUCT proceedings.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal cost, which reduces the investment rate base and the resultant return, will be discharged as removal costs are incurred.

Texas Restructuring Related Regulatory Assets and Liabilities

Designated for Securitization, Wholesale Capacity Auction True-up and Refunded Excess Earnings regulatory assets and 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. See Note 6 for a discussion of our efforts to recover 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 the Cook Plant related outage restart costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to Maintenance and Other Operation Expense under the settlement agreements was $40 million in 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 were amortized as a reduction of revenues. The amortization of amounts deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected I&M's Statement of Income in 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 beginning in the third quarter of 2000:

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.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the remaining periods of the merger agreements, future results of operations and cash flows could be adversely affected.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

With the passage of restructuring legislation, six of AEP's twelve 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, Michigan, Virginia and Texas) in which the AEP electric utility companies operate. The following paragraphs discuss significant events related to industry restructuring in those states.

TEXAS RESTRUCTURING – Affecting TCC, TNC and SWEPCo

The 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. The PUCT has begun studies to consider further delay of customer choice in the SPP area of Texas. TCC and TNC operate in ERCOT while SWEPCo and a small portion of TNC's business operates in SPP.

The Texas Restructuring Legislation provides for True-up Proceedings to determine the amount and recovery of:

- net stranded generation plant costs and net generation-related regulatory assets less any 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 PUCT's 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 certain of the above true-up amounts.

In May 2005, TCC filed its True-Up Proceeding seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items including carrying costs through September 30, 2005. The PUCT issued a final order in February 2006, which determined that TCC's net true-up regulatory asset was $1.5 billion, which included carrying costs through September 2005. Other parties may appeal the PUCT's final order as unwarranted or too large; we expect to appeal, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules.

TCC adjusted its December 2005 books to reflect the PUCT's final order. Based on the final order, TCC's net true-up regulatory asset was reduced by $384 million. Of the $384 million, $345 million was recorded in December 2005 as a pretax extraordinary loss. The difference between the requested amount of $2.4 billion, the approved amount of $1.5 billion and the recorded amount of $1.3 billion at December 31, 2005 is detailed in the table below:

	in millions
True-Up Proceeding Requested Amount	$ 2,406
Wholesale Capacity Auction True-up, including carrying costs	(572)
Commercial Unreasonableness Disallowance	(122)
Return on and of Stranded Costs Disallowance	(159)
Other	(78)
Amount Approved by the PUCT	1,475
Unrecognized but Recoverable Equity Carrying Costs and Other	(200)
Total Recorded Net True-up Regulatory Asset	$ 1,275

The requested $2.4 billion represents what TCC believes it should recover under its interpretation of the provisions of the Texas Restructuring Legislation. However, the $1.3 billion book amount reflects what management believes to be the probable recoverable net regulatory true-up asset at December 31, 2005, taking into account the PUCT's final order in TCC's True-up Proceeding exclusive of various items, principally recoverable but unrecognized equity carrying costs and other items.

Based on the PUCT-approved amount, and carrying costs through the proposed date of securitization, we anticipate requesting to securitize $1.8 billion, as discussed below in the "TCC Securitization Proceeding" section.

The Components of TCC's Net True-up Regulatory Asset as of December 31, 2005 and December 31, 2004 are:

	TCC	
	December 31, 2005	December 31, 2004
	(in millions)	
Stranded Generation Plant Costs	$ 969	$ 897
Net Generation-related Regulatory Asset	249	249
Excess Earnings	(49)	(10)
Net Stranded Generation Costs Before Carrying Costs	1,169	1,136
Carrying Costs on Stranded Generation Plant Costs	267	225
Net Stranded Generation Costs After Carrying Costs	1,436	1,361
Wholesale Capacity Auction True-up	61	483
Carrying Costs on Wholesale Capacity Auction True-up	16	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(177)	(212)
Net Other Recoverable True-up Amounts	(161)	287
Total Recorded Net True-up Regulatory Asset	$ 1,275	$ 1,648

The majority of the reduction to TCC's net true-up regulatory asset was comprised of two extraordinary adjustments, and the associated nonextraordinary debt carrying costs. The major adjustments were related to TCC's wholesale capacity auction true-up and its stranded plant cost from the sale of its generating plants. The PUCT found that TCC did not comply with the wholesale capacity auction requirements, which resulted in a book reduction of $422 million. Related to the sale of TCC's generation assets, the PUCT determined that TCC acted in a manner that was commercially unreasonable in large part because it failed to determine a minimum price at which it would reject bids for the sale of its generating plants. Based on that determination, TCC reduced its net true-up regulatory asset by $122 million. Other smaller adjustments totaling $7 million were reversed as an extraordinary item.

In addition, the PUCT determined that the purpose of the capacity auction true-up was to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the

duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded generation plant cost balance that it determined was included in the capacity auction true-up. Since TCC had previously reduced its book stranded cost regulatory asset by $238 million in 2004 related to the duplicate depreciation, TCC increased its book stranded generation plant cost by $206 million in December 2005. The reduction to debt carrying costs related to all of these adjustments totaled $71 million.

In 2003 and 2004, based upon orders received from the PUCT, TCC recorded provisions to its over-recovered fuel balance resulting in a $209 million over-recovery regulatory liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed as nonextraordinary in the fourth quarter of 2005.

In a future proceeding, certain adjustments for the future cost-of-money benefit of accumulated deferred federal income taxes may be deducted from the recoverable true-up asset, and transferred to a separate regulatory asset to be recovered in normal delivery rates outside of the securitization process which would affect the timing of cash recovery.

TCC believes that significant aspects of the decision made by the PUCT are contrary to both the statute by which the legislature restructured the electric industry in Texas and the regulations and orders the PUCT has issued in implementing that statute. TCC intends to seek rehearing of the PUCT's rulings. If the PUCT does not make significant changes in response to our request for reconsideration, we expect that TCC will challenge certain of the PUCT's rulings through appeals to Texas state and federal courts. Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any requested rehearings or appeals.

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In TCC's final true-up order, the PUCT reduced net stranded generation costs by $51 million related to the present value of Accumulated Deferred Investment Tax Credits (ADITC) and by $10 million related to excess deferred federal income taxes (EDFIT) associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions. Also included in the final true-up order was language whereby the PUCT agreed to consider revisiting this issue if the Internal Revenue Service (IRS) ruled that the flow-through of ADITC and EDFIT constituted a normalization violation. Tax counsel has advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a final, nonappealable rate order. With the agreement in effect, as well as our ability to ultimately appeal the final true-up order, management does not believe a normalization violation has occurred. Although ADITC and EDFIT are recorded as a liability on TCC's books, such amounts are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table.

The IRS issued proposed regulations in March 2003 that would have liberalized the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS had not issued final regulations, TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. In December 2005, the IRS withdrew these previously proposed regulations and issued new proposed regulations. The new proposed regulations removed the retroactive election that allowed utilities, which were deregulated before March 4, 2003, to pass the benefits of ADITC and EDFIT back to ratepayers. The PUCT computation is premised on the withdrawn proposed regulations and may not be acceptable to the IRS under the new proposed regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates $105 million as of December 31, 2005 and also a loss of the ability to elect accelerated tax depreciation in the future. In light of the new proposed regulations, we are unable to predict how the IRS will ultimately rule on our private letter ruling request. However, prior precedent in this area would lead management to expect the IRS to rule that the PUCT approach of reducing the stranded cost recovery by the present value of its ADITC and EDFIT would, if ultimately imposed by a final, nonappealable order, constitute a normalization violation. Management intends to update the private letter ruling request for the new proposed regulations and issuance of the final order and will continue to work closely with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

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. Under the Texas Restructuring Legislation, since TNC and SWEPCo do not have stranded generation plant costs, excess earnings have been applied to reduce transmission and distribution capital expenditures. Management believes excess earnings for TNC and SWEPCo are not true-up items. However, in January 2005, intervenors filed testimony in TNC's True-up Proceeding recommending that TNC's 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. In addition, intervenors also recommended that TNC's transmission and distribution rates should be reduced by a maximum amount of approximately $3 million on an annual basis related to excess earnings. The PUCT did not address the excess earnings in the final true-up order, and instead required that excess earnings be addressed in TNC's Competition Transition Charge (CTC) filing. TNC's CTC filing was made in August 2005. As noted below, this filing has been suspended until further notice.

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 reduced cash flows over the refund period. Through the end of 2004, TCC had refunded all but $10 million of its excess earnings liability. During 2005, TCC refunded an additional $9 million reducing its unrefunded excess earnings to $1 million. In July 2005, the PUCT approved a preliminary order in TCC's True-up Proceeding that instructed TCC to stop refunding the excess earnings and to offset the remaining balance, which was $1 million, against net stranded generation costs. In the final true-up order, the PUCT has utilized $1 million as a reduction to TCC's net stranded generation costs. However, prior to the final true-up order, in September 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings was unlawful under the Texas Restructuring Legislation. The decision stated that the excess earnings should have been treated as a reduction of stranded costs. As such, in September 2005, TCC recorded a regulatory asset of $56 million (including $7 million of interest) for the future recovery of the $49 million refunded to the REPs and a reduction to net stranded plant regulatory assets of $49 million, which also reduced the amount of carrying costs on TCC's books by $9 million. The PUCT filed a petition with the Texas Supreme Court to review the Texas Court of Appeals' decision. Management is unable to predict the ultimate outcome of these proceedings.

Wholesale Capacity Auction True-up and Stranded Plant Cost

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. 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 of $483 million in those years. TCC also recorded $126 million of carrying costs related to the wholesale capacity auction true-up, increasing the total asset to $609 million. As noted earlier, the PUCT ruled in the True-up Proceeding that TCC did not comply with the PUCT's rules regarding the auction of 15% of its Texas jurisdictional installed generation capacity. Based upon this ruling, TCC's capacity auction revenues were computed at higher nonauction prices and, as a result, TCC wrote off $422 million of its recorded regulatory asset and $110 million of related carrying costs. At December 31, 2005, TCC has a net true-up recoverable asset related to the wholesale capacity auction true-up of $77 million inclusive of remaining carrying costs.

In a nonaffiliated company's order, the PUCT also reduced that company's requested wholesale capacity auction true-up request. The PUCT determined that the nonaffiliated company had not met the PUCT's rules regarding the auction of 15% of its generation capacity because it failed to sell 15% of its generating capacity. That utility appealed the PUCT's decision to the Texas District Court. The District Court found that the PUCT erred by disallowing a significant portion of that utility's wholesale capacity auction true-up request. Although the facts regarding the nonaffiliated company's wholesale capacity auction true-up request and TCC's wholesale capacity auction true-up request are not exactly the same, management believes the District Court decision is a positive outcome and will prove to be beneficial to TCC's future claim that it is entitled to a significant portion, if not all, of TCC's requested amount.

In addition, the PUCT determined that the purpose of the capacity auction true-up is to provide a traditional regulated level of recovery during 2002 through 2003. The PUCT then determined that TCC recovered $238 million of duplicate depreciation through its wholesale capacity auction true-up. However, TCC successfully argued that the duplicate depreciation adjustment should be offset by the amount by which TCC under-earned its allowed return on equity in 2002 and 2003 of $206 million. Therefore, to avoid double recovery of stranded costs, the PUCT disallowed $32 million from TCC's requested stranded plant cost balance that it determined was included in the capacity auction true-up. Since TCC had reduced its booked stranded cost regulatory asset by $238 million in December 2004 related to the duplicate depreciation, TCC increased its stranded plant cost regulatory asset by $206 million effectively adjusting its books to recognize the significantly lower $32 million net disallowance.

Retail Clawback

The Texas Restructuring Legislation provides for the affiliated PTB REPs serving residential and small commercial customers to refund to their 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. At December 31, 2005, TCC's recorded retail clawback regulatory liability was $61 million and TNC's was $14 million. TCC recorded a receivable from the nonaffiliated company which operates as their PTB REP totaling $61 million, for the retail clawback liability. TNC received payment of $14 million from its nonaffiliated PTB REP in 2005, but has not refunded this money to its customers as of December 31, 2005. TNC's CTC proceeding, the proceeding that will determine the refund methodology, has been suspended. TCC received payment from its nonaffiliated REP in February 2006.

Fuel Balance Recoveries

In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred fuel balance for inclusion in their True-up Proceedings. The PUCT issued final orders in each of these proceedings that resulted in significant disallowances for both companies. Based upon these orders, TCC increased its over-recovered fuel balance by a total of $140 million, which resulted in a $209 million over-recovery liability. In TCC's final fuel reconciliation proceeding, the PUCT's order provided for a $177 million over-recovered balance resulting in an over-provision of $32 million, which was reversed in the fourth quarter of 2005. TNC's under-recovered balance was adjusted by a total of $31 million. After the adjustments, TNC's under-recovered balance became an over-recovery of $5 million. Both TCC and TNC have challenged the PUCT's rulings regarding a number of issues in the fuel orders in federal and state court. Intervenors have also challenged certain rulings in the PUCT fuel order in state court.

In September 2005, the Texas District Court in Travis County issued a ruling which upheld the PUCT's decisions in the TNC proceeding. TNC and other parties have filed notice of appeal of that decision. TCC has not received a ruling from the Texas District Court regarding its appeal.

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the favorable federal TNC ruling is applicable to its appeal. The impact of the court order could result in reductions to the over-recovered fuel balances of $8 million for TNC and $14 million for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for

the Fifth Circuit. If the PUCT is unsuccessful in the Federal Court system, it could file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT is unsuccessful in its federal court appeal, TCC and TNC can reverse their provisions. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies. This is because the ruling may result in a reallocation of off-system sales margins between AEP East companies and AEP West companies. If that occurs, the AEP West companies would receive additional off-system sales margins from the AEP East companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the additional payments from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

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.

In June 2004, the Texas Supreme Court determined that carrying costs 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 a nonaffiliated company's true-up order, the PUCT addressed the Supreme Court's remand decision and specified the manner in which carrying costs should be calculated. Based on this order, TCC first recorded carrying costs in 2004 and continued to accrue carrying costs in 2005. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. As a result, TCC recorded a $27 million reduction in its carrying costs in the first quarter of 2005 and reduced the amount of carrying costs accrued for the remainder of 2005. The PUCT indicated that it will address this retrospective ADFIT cost of money benefit in TCC's securitization proceeding.

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax cost of capital rate from its unbundled cost of service rate proceeding. The embedded debt component of the carrying cost rate is 8.12%. Based on the final order in TCC's True-up Proceeding, TCC reversed, in December 2005, $71 million of carrying costs, resulting in a net $19 million reduction in total carrying costs for 2005. Through December 2005, TCC recorded $283 million of carrying costs ($267 million on stranded generation plant costs and $16 million on wholesale capacity auction true-up). The remaining equity component of $153 million will be recognized in income as collected. TCC will continue to accrue a carrying cost.

In January 2006, the PUCT approved publication of a proposed rule that would reduce the 11.79% rate of return on nonsecuritized true-up amounts to the most recently approved weighted average cost of debt, which would be 5.70% for TCC. The effective date of the change is proposed to be (i) January 1, 2002 for utilities that have not received a final true-up order or (ii) the date the rule is adopted for utilities that have received a final order. There will be a 45-day comment period regarding the rule. TCC received a final order (which is subject to rehearing) in the True-up Proceeding in February 2006. AEP will assert in comments filed in the rulemaking proceeding that the rule change should not have retroactive application. However, TCC cannot predict if the rule will be adopted, or if it will be adopted in its present prospective form for utilities that have received their final true-up order.

The deferred over-recovered fuel balance accrues interest payable at a short-term rate set by the PUCT until a final order is issued in TCC's True-up Proceeding. At that time, carrying costs accrue on the deferred fuel. For the retail clawback, carrying costs accrue when a final order is issued in TCC's True-up Proceeding.

TCC Securitization Proceeding

TCC anticipates filing an application in March 2006 requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs to September 1, 2006. The $1.8 billion does not include TCC's other true-up items, which TCC anticipates will be negative, and as such will reduce rates to customers through a negative competition transition charge. The estimated amount for rate reduction to customers, including carrying costs through August 31, 2006, is approximately $475 million. TCC will incur carrying costs on the negative balances until fully refunded. The principal components of the rate reduction would be an over-recovered fuel balance, the retail clawback and an ADFIT benefit related to TCC's stranded generation cost, and the positive wholesale capacity auction true-up balance. TCC anticipates making a filing to implement its CTC for other true-up items in the second quarter of 2006. It is possible that the PUCT could choose to reduce the securitization amount by all or some portion of the negative other true-up items. If that occurs, or if parties are successful in their appeals to reduce the recoverable amount, a material negative impact on the timing of TCC's cash flows would result. Management is unable to predict the outcome of these anticipated filings.

The difference between the recorded amount of $1.3 billion and our planned securitization request of $1.8 billion is detailed in the table below:

	In millions
Total Recorded Net True-up Regulatory Asset as of December 31, 2005	**$ 1,275**
Unrecognized but Recoverable Equity Carrying Costs and Other	200
Estimated January 2006 – August 2006 Carrying Costs	144
Securitization Issuance Costs	24
Net Other Recoverable True-up Amounts (a)	161
Estimated Securitization Request	**$ 1,804**

(a) If included in the proposed securitization as described above, this amount, along with the ADFIT benefit, is refundable to customers over future periods through a negative competition transition charge.

The final order did not address the allocation of stranded costs to TCC's wholesale jurisdiction which will be addressed in TCC's securitization proceeding. TCC estimates the amount allocated to wholesale is less than $1 million. However, TCC cannot predict the ultimate amount the PUCT will allocate to the wholesale jurisdiction that TCC will not be able to securitize.

TCC True-up Proceeding Summary

We believe that our recorded net true-up regulatory asset at December 31, 2005 of $1.3 billion accurately reflects the PUCT's final order in TCC's True-up Proceeding. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the net transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no additional impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding. If we determine in future securitization and CTC proceedings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset of $1.3 billion at December 31, 2005 and we are able to estimate the amount of such nonrecovery, we will record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC intends to pursue rehearing and appeals to vigorously seek relief as necessary in both federal and state court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

The Components of TNC's True-up Regulatory Liability as of December 31, 2005 and December 31, 2004 are:

	TNC	
	December 31, 2005	December 31, 2004
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	$ (19)	$ (18)

TNC completed its True-up Proceeding in 2005 with the PUCT issuing a final order in May 2005. Based upon that final order, TNC adjusted its true-up regulatory liability. TNC filed a CTC proceeding in August 2005 to establish a rate to refund the net true-up regulatory liability. That filing has been suspended until the ruling from TNC's appeal to federal court regarding its final fuel reconciliation is fully resolved. This federal court ruling is discussed above. TNC accrues interest expense on the unrefunded balance and will continue accruing interest expense until the balance is fully refunded.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

The Ohio Electric Restructuring Act of 1999 (Restructuring Act) provided for a Market Development Period (MDP) during which retail customers could 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 ended on December 31, 2005. 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. As of December 31, 2005, none of OPCo's customers have elected to choose an alternate power supplier and only a modest number of CSPCo's small commercial customers have switched suppliers.

The PUCO invited default service providers to propose an alternative to all customers moving to market prices on January 1, 2006. In February 2004, CSPCo and OPCo (the Ohio companies) filed Rate Stabilization Plans (RSP) 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 AEP's generation resources that serve Ohio customers.

In January 2005, the PUCO approved the RSP for the Ohio companies. The approved plans provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues for specified costs. CSPCo's cost recovery under the Power Acquisition Rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding (see "Acquisitions" section of Note 10) will diminish CSPCo's potential for the additional annual 4% generation rate increases in 2006 by approximately one-half and to a lesser extent in 2007 and 2008. The plans also provide that the Ohio companies can recover in 2006, 2007 and 2008 environmental carrying costs and PJM-related administrative costs and congestion costs net of firm transmission rights (FTR) revenue from 2004 and 2005 related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $9 million for CSPCo and $47 million for OPCo in 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo related to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding its approval of the RSP. In March 2005, the PUCO denied all applications for rehearing. In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court which challenged the RSP and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. If the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo's and OPCo's future earnings will be adversely affected. In a nonaffiliated utility's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In addition, if the RSP order were determined on appeal to be illegal under the Restructuring Act, it

would have an adverse effect on results of operations, cash flows and possibly financial condition. Although CSPCo and OPCo believe that the RSP plan is legal and intend to defend vigorously the PUCO's order, management cannot predict the ultimate outcome of the pending litigation.

In July 2005, CSPCo and OPCo each filed applications with the PUCO to decrease the transmission rates contained in their retail electric rates in order to reflect the FERC-approved OATT rate. Those applications were supplemented in December 2005 to update the proposed transmission rates to reflect the rates filed as part of a settlement agreement with the FERC (see "RTO Formation/Integration Costs" section of Note 4). As a result, annual transmission rates would be reduced by approximately $12 million and $13 million for CSPCo and OPCo, respectively. In accordance with the Restructuring Act, the Ohio companies also proposed to increase their distribution rates to fully offset the resulting decrease in their transmission rates. The PUCO approved these applications on December 28, 2005 and the new offsetting transmission and distribution rates became effective on that date. Under the terms of the PUCO's order in the RSP, the modified distribution rates in effect on December 31, 2005 are frozen though December 31, 2008 with certain exceptions, including governmentally-imposed changes resulting in increased distribution costs, changes in taxes or for major storm damage service restoration.

In September 2005, the Ohio companies filed with the PUCO to recover through a Transmission Cost Recovery Rider, beginning January 1, 2006, approximately $5 million for CSPCo and $7 million for OPCo of projected 2006 annual net costs incurred as a result of joining PJM. In addition, the Ohio companies requested to practice over/under-recovery deferral accounting for any differences between the revenues collected starting January 1, 2006 and the actual PJM costs incurred. In December 2005, the PUCO issued an order approving the rider components.

In February 2006, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective the later of August 2006 or the first day of the month in which the Wyoming-Jacksons Ferry transmission line enters service in order to reflect their share of costs for that new line. Management anticipates that, if approved, the filing will result in increased revenues for CSPCo and OPCo of $32 million and $42 million, respectively, in 2006 increasing in 2007 to $46 million and $59 million for CSPCo and OPCo, respectively. This filing follows the settlement of our March 2005 filing with the FERC requesting increased OATT rates in which AEP received a three-step increase (see "FERC Order on Regional Through and Out Rates and Mitigating SECA Revenue" section of Note 4).

The PUCO's order in the RSP requires CSPCo and OPCo to allot a combined total of $14 million of previously provided for unused CSPCo shopping incentives to benefit low-income customers and economic development programs over the three-year period ending December 31, 2008. In a March 2005 rehearing order, the PUCO clarified that the Ohio companies have a regulatory liability of only $14 million of unused shopping incentives. In the second quarter of 2005, CSPCo ceased applying unused shopping incentives to reduce its recoverable transition regulatory asset. Assuming that the $14 million regulatory liability is allocated equally to CSPCo and OPCo, in 2005, CSPCo increased its recoverable transition regulatory asset by $18 million due to the reversal of the unused shopping incentives, transferred $7 million to a regulatory liability and credited the remaining $11 million to pretax earnings and OPCo recorded a regulatory liability of $7 million which it charged to pretax earnings.

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies 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, 2005, CSPCo incurred $44 million and deferred $21 million and OPCo incurred $46 million and deferred $22 million of such costs for probable future recovery in distribution rates. CSPCo and OPCo have not yet recorded $3 million and $4 million, respectively, of equity carrying costs which are not recognized until collected. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. The Ohio companies believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio 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 the Ohio companies' future results of operations and cash flows.

MICHIGAN RESTRUCTURING – Affecting I&M

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date, the rates on I&M's 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&M's total base rates in Michigan remain unchanged and reflect cost of service. At December 31, 2005, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2005 the requirements to apply SFAS 71 continue to be met since I&M's 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 extended 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. Under the restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the revised restructuring law, APCo is deferring incremental environmental generation costs for future recovery.

ARKANSAS RESTRUCTURING – Affecting SWEPCo

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on SWEPCo's results of operations and financial condition.

WEST VIRGINIA RESTRUCTURING – Affecting APCo

In 2000, the 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 2001 through 2003, the West Virginia Legislature failed to enact the required tax legislation and the WVPSC closed its dockets. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in West Virginia. In March 2003, APCo's outside counsel advised that restructuring in West Virginia was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's West Virginia generation. As a result, in March 2003, management concluded that deregulation of APCo's 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 APCo's 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 NSR requirements 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. A bench trial on the liability issues was held during July 2005. Briefing has concluded but no decision has been issued.

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 ($32,500 after March 15, 2004) per day per violation at each generating unit. 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.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned), and Stuart (26% owned) Stations. Similar cases have been filed against other nonaffiliated utilities.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability AEP subsidiaries might have 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, management believes AEP subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If any of the AEP subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In July 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 several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

In July 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. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

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 East Companies and West Companies

In July 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, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions allege that CO_2 emissions from the defendant's power plants constitute a public

nuisance under federal common law due to impacts associated with global warming, and sought 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. In September 2005, the lawsuits were dismissed. The trial court's dismissal has been appealed to the Second Circuit Court of Appeals and briefing continues. Management believes the actions are without merit and intends to defend vigorously against the claims.

Ontario Litigation – Affecting CSPCo and OPCo

In June 2005, CSPCo, OPCo and several nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. AEP has not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted NO_X, SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. Management believes CSPCo and OPCo have meritorious defenses to this action and intend to defend vigorously against it.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting AEP System

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 treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2005, APCo and I&M are each named as a Potentially Responsible Party (PRP) for one site and CSPCo and OPCo are each named a PRP for two sites by the Federal EPA. There are seven additional sites for which APCo, CSPCo, I&M, KPCo, OPCo, and SWEPCo have received information requests which could lead to PRP designation. I&M, OPCo, SWEPCo, TCC and TNC have also been named potentially liable at seven sites under state law. In those instances where we have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

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, present estimates do not anticipate material cleanup costs for identified sites for which certain Registrant Subsidiaries have been declared PRPs. If significant cleanup costs were attributed to those Registrant 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 electricity prices.

NUCLEAR – *Affecting I&M*

Nuclear Plant

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. I&M has a significant future finance commitment to safely dispose of SNF and to decommission and decontaminate the plant. 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 is 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, which must be carried for each licensed reactor, 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 $15 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $30 million. 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 is also obligated for assessments of up to $6 million for potential claims until December 31, 2007.

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $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 utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $41 million which is assessable if the insurer's financial resources would be inadequate to pay for losses.

In 2005, the Price-Anderson Act was extended by amendment through December 31, 2025.

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 the Cook Plant is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $236 million for fuel consumed prior to April 7, 1983 at the 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, 2005, funds collected from customers towards payment of the pre-April 1983 fee and related earnings of $264 million are in external trust funds.

SNF Litigation

The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. 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. The DOE failed to begin accepting SNF by the January 1998 deadline in the law. DOE continues to fail 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, I&M, 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 nuclear waste will not be ready until at least 2010. In 1998, we 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 January 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability.

The case was tried in March 2004 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, ruling that pre-breach and post-breach damages are not recoverable in a partial breach case. In July 2004, I&M appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. In September 2005, the U.S. Court of Appeals ruled that the trial court erred in ruling that pre-breach damages in a partial breach case are per se not recoverable, but denied I&M's pre-breach damages on the facts alleged. The Court of Appeals also ruled that the trial court did not err in determining that post-breach damages are not recoverable in a partial breach case, but determined that I&M may recover post-breach damages in later suits as the costs are incurred.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. After expiration of the licenses, the 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 the Cook Plant ranges from $889 million to $1.1 billion in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions. 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 was $27 million in 2005, 2004 and 2003.

Decommissioning costs recovered from customers are deposited in external trusts. I&M deposited in its decommissioning trust an additional $4 million in 2005 and 2004 and $12 million in 2003 related to special regulatory commission approved funding for decommissioning of the Cook Plant. At December 31, 2005, the total decommissioning trust fund balance for Cook Plant was $870 million. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs for the Cook Plant including interest, unrealized gains and losses and expenses of the trust funds, increase or decrease the recorded liability.

Estimates from the decommissioning study 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 will work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, I&M 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.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The Registrant Subsidiaries have substantial construction commitments to support its operations and environmental investments. The following table shows the estimated construction expenditures by company for 2006:

	(in millions)
AEGCo	$ 14
APCo	943
CSPCo	343
I&M	311
KPCo	100
OPCo	1,070
PSO	279
SWEPCo	288
TCC	278
TNC	73

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.

Certain Registrant Subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2017 for APCo, 2015 for CSPCo, 2014 for I&M, 2008 for KPCo, 2021 for OPCo, 2008 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.

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 and costs of replacement power in the event of a nuclear incident at the Cook Plant. 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.

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 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) 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.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleged that TEM breached the PPA, and sought a determination of its rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In April 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 was terminated and (iii) would be pursuing against TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM had breached the contract and awarded damages to OPCo of $123 million plus pre-judgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. OPCo asked the court to modify the judgment to (i) award a termination payment to OPCo under the terms of the PPA; (ii) grant OPCo's attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted AEP's motion for reconsideration concerning TEM's parent guaranty and increased AEP's judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found to be unenforceable by the court ultimately deciding the case, OPCo could be adversely affected to the extent OPCo is unable to find other purchasers of the power with similar contractual terms and to the extent claimed termination value damages are not fully recovered from TEM.

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. Upon repeal of PUHCA on February 8, 2006, the SEC dismissed the proceeding challenging AEP's merger with CSW.

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 of its subsidiaries, including TCC and TNC, ERCOT and a number of nonaffiliated energy companies. The action alleged 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 alleged that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced TCE into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleged over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. The Court dismissed all claims against the AEP companies. TCE appealed the trial court's decision and the appellate court affirmed the lower court's decision. TCE filed a Petition for Writ of Certiorari with the United States Supreme Court, which was denied in January 2006. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit against the same defendants and others. In December 2005, the federal court dismissed the plaintiffs' federal claims with prejudice and dismissed their state law claims without prejudice. After that decision, AEP and its subsidiaries settled all claims with plaintiffs in a settlement, subject to a confidentiality clause, and without material impact on results of operations or financial condition.

Coal Transportation Dispute – Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant 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 provisions for possible loss in 2004 and 2005. The provision was deferred as a regulatory asset under PSO's fuel mechanism and immaterially affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate. BNSF contends that it was underpaid approximately $9.5 million, including interest. This matter was submitted to an arbitration panel in January 2006.

FERC Long-term Contracts – Affecting AEP East Companies 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 AEP's favor and dismissed the complaint filed by the two Nevada utilities. In 2001, the utilities 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 ALJ's 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 in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees. 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 (LOCs) with third parties. These LOCs cover items such as 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, 2005, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, each with a maturity of March 2006.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $53 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provided 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, 2005, 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. After consolidation, SWEPCo records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses.

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which 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 2005, 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. TCC sales agreements include indemnifications with a maximum exposure of $443 million related to the sale price of its generation assets. See "Texas Plants – TCC and TNC Generation Assets" section of Note 10. There are no material liabilities recorded for any indemnifications.

Registrant Subsidiaries are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies and AEP West companies and for activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Master Operating Lease

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, 2005, 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	$ 6
CSPCo	3
I&M	4
KPCo	2
OPCo	5
PSO	5
SWEPCo	5
TCC	6
TNC	3

9. COMPANY-WIDE STAFFING AND BUDGET REVIEW

The following table shows the severance benefits expense recorded in 2005 (primarily in Other Operation) resulting from a company-wide staffing and budget review, including the allocation of approximately $19 million of severance benefits expense associated with AEPSC employees among the Registrant Subsidiaries. AEGCo has no employees, but receives allocated expenses. Remaining accruals, reflected primarily in Current Liabilities – Other, range from $8 thousand to $1.1 million as of December 31, 2005, and are expected to be settled by the end of the second quarter of 2006.

Year Ended December 31, 2005	
Company	(in millions)
AEGCo	$ 0.3
APCo	4.5
CSPCo	2.6
I&M	4.7
KPCo	1.1
OPCo	3.9
PSO	1.4
SWEPCo	1.8
TCC	4.3
TNC	1.3

10. ACQUISITIONS, DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND OTHER LOSSES

ACQUISITIONS

2005

Waterford Plant - Affecting CSPCo

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company - Affecting CSPCo

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, AEP agreed to terms of a transaction, which includes the transfer of Monongahela Power's Ohio customer base and the assets that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately $46 million and the assumption of liabilities of approximately $2 million. In addition, CSPCo paid $10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's $10 million payment was recorded as a regulatory asset and will be recovered with a carrying cost from all of its customers over approximately 5 years. Also included in the proposed transaction is a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station - Affecting APCo

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of a 505 MW plant located near Ceredo, West Virginia. This transaction was completed in December 2005 for $100 million.

DISPOSITIONS

2005

Texas Plants – South Texas Project - Affecting TCC

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 TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on TCC's results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it did not operate individually, but rather as a part of the AEP System, which included all of the generation facilities owned by the Registrant Subsidiaries. TCC's assets and liabilities related to STP were classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, in its Consolidated Balance Sheet as of December 31, 2004.

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 ERCOT's 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 an 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 ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, TNC recorded a pretax write-down of utility assets of approximately $34 million in 2002. 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 in 2002.

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 of $4 million in the fourth quarter of 2002. In addition, TNC recorded related inventory write-downs of $3 million. Similarly, TCC recorded an additional pretax asset impairment write-down of $7 million, which was deferred and recorded in regulatory assets in 2002. TCC also recorded related inventory write-downs and adjustments of $18 million which were deferred and recorded in regulatory assets.

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 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 TCC's Consolidated Balance Sheets. In accordance with the Texas Restructuring Legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which was expected to be recovered through a wires charge, subject to the final outcome of the True-up Proceeding (see "Texas Restructuring" section of Note 6).

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 TCC's 2004 results of operations.

The remaining generation assets and liabilities of TCC are classified as Assets Held for Sale – Texas Generation Plants and Liabilities Held for Sale – Texas Generation Plants, respectively, on TCC's Consolidated Balance Sheets. See "Assets Held for Sale" section of this note for additional information.

2003

Water Heater Assets – Affecting 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. AEP sold its water heater rental program and recorded a pretax loss in the first quarter of 2003 based upon final terms of the sale agreement. AEP provided for pretax charges in the fourth quarter of 2002 based on an estimated sales price. See below for amounts of the loss by company:

Subsidiary Company	Loss on Sale Recorded in 2003 (Pretax)
	(in thousands)
APCo	$ 56
CSPCo	740
I&M	787
KPCo	11
OPCo	2,165

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station-Affecting TCC

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. By 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 TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were 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 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 requested that the court declare the co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of the unrelated party on October 10, 2005. TCC and the other nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. A decision by the Appeals Court is expected during the first half of 2006. 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. TCC's 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, on TCC's Consolidated Balance Sheets at December 31, 2005 and 2004. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by the Registrant Subsidiaries.

The assets and liabilities of the entities held for sale at December 31, 2005 and 2004 are as follows:

	As of December 31,	
Texas Plants (TCC)	2005	2004
	(in millions)	
Assets:		
Other Current Assets	$ 1	$ 24
Property, Plant and Equipment, Net	43	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale - Texas Generation Plants	$ 44	$ 628
Liabilities:		
Regulatory Liabilities	$ -	$ 1
Asset Retirement Obligations	-	249
Total Liabilities Held for Sale - Texas Generation Plants	$ -	$ 250

OTHER LOSSES

2005

Conesville Units 1 and 2 – Affecting CSPCo

In the third quarter of 2005, following an extensive review of the commercial viability of CSPCo's Conesville units 1 and 2, CSPCo committed to a plan to retire these units before the end of their previously estimated useful lives. As a result, Conesville units 1 and 2 were considered retired as of the third quarter of 2005.

A pretax charge of approximately $39 million was recognized in 2005 related to CSPCo's decision to retire the units. The impairment amount is classified as Asset Impairments and Other Related Charges in CSPCo's 2005 Consolidated Statement of Income.

2003

Blackhawk Coal Company – Affecting 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 operations 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 management's 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 Assets Impairments in I&M's Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored 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. 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. 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. As a result of implementing FSP FAS 106-2, the tax-free subsidy reduced 2004's 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 plan's measurement date of December 31, 2005, and a statement of the funded status as of December 31 for both years:

Pension Obligations, Plan Assets, Funded Status as of December 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Change in Projected Benefit Obligation:				
Projected Obligation at January 1	$ 4,108	$ 3,688	$ 2,100	$ 2,163
Service Cost	93	86	42	41
Interest Cost	228	228	107	117
Participant Contributions	-	-	20	18
Actuarial (Gain) Loss	191	379	(320)	(130)
Benefit Payments	(273)	(273)	(118)	(109)
Projected Obligation at December 31	$ 4,347	$ 4,108	$ 1,831	$ 2,100
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$ 3,555	$ 3,180	$ 1,093	$ 950
Actual Return on Plan Assets	224	409	70	98
Company Contributions	637	239	107	136
Participant Contributions	-	-	20	18
Benefit Payments	(273)	(273)	(118)	(109)
Fair Value of Plan Assets at December 31	$ 4,143	$ 3,555	$ 1,172	$ 1,093
Funded Status:				
Funded Status at December 31	$ (204)	$ (553)	$ (659)	$ (1,007)
Unrecognized Net Transition Obligation	-	-	152	179
Unrecognized Prior Service Cost (Benefit)	(9)	(9)	5	5
Unrecognized Net Actuarial Loss	1,266	1,040	471	795
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

Amounts Recognized in the Balance Sheets as of December 31, 2005 and 2004

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Prepaid Benefit Costs	$ 1,099	$ 524	$ -	$ -
Accrued Benefit Liability	(46)	(46)	(31)	(28)
Additional Minimum Liability	(35)	(566)	N/A	N/A
Intangible Asset	6	36	N/A	N/A
Pretax Accumulated Other Comprehensive Income	29	530	N/A	N/A
Net Asset (Liability) Recognized	$ 1,053	$ 478	$ (31)	$ (28)

N/A = Not Applicable

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2006	2005	2004
Asset Category	(in percentages)		
Equity Securities	70	66	68
Debt Securities	28	25	25
Cash and Cash Equivalents	2	9	7
Total	100	100	100

The asset allocations for AEP's other postretirement benefit plans at the end of 2005 and 2004, and target allocation for 2006, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2006	2005	2004
Asset Category	(in percentages)		
Equity Securities	66	68	70
Debt Securities	31	30	28
Other	3	2	2
Total	100	100	100

AEP's 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 the $320 million and $200 million contributions at the end of 2005 and 2004, respectively, 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 2006 and 2005.

The value of AEP's pension plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The qualified plans paid $263 million in benefits to plan participants during 2004 (nonqualified plans paid $10 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.

	2005	2004
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 4,053	$ 3,918
Nonqualified Pension Plans	81	80
Total	$ 4,134	$ 3,998

Minimum Pension Liability

AEP's combined pension funds are underfunded in total (plan assets are less than projected benefit obligations) by $204 million and $553 million at December 31, 2005 and December 31, 2004, respectively. For AEP's 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, 2005 and 2004 were as follows:

	Underfunded Pension Plans As of December 31,	
	2005	2004
	(in millions)	
Projected Benefit Obligation	$ 84	$ 2,978
Accumulated Benefit Obligation	81	2,880
Fair Value of Plan Assets	-	2,406
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	81	474

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 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

AEP made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, 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 AEP's benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in percentages)			
Discount Rate	5.50	5.50	5.65	5.80
Rate of Compensation Increase	5.90(a)	3.70	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

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 Moody's 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, 2005 and 2004 under this method was 5.50% for pension plans and 5.65% and 5.80%, respectively, for other postretirement benefit plans.

For 2005, the rate of compensation increase assumed varies with the age of the employee, ranging from 5.0% per year to 11.5% per year, with an average increase of 5.9%.

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:

Employer Contributions	Pension Plans 2006	Pension Plans 2005	Other Postretirement Benefit Plans 2006	Other Postretirement Benefit Plans 2005
	(in millions)			
Required Contributions (a)	$ 8	$ 10	N/A	N/A
Additional Discretionary Contributions	-	$ 626 (b)	$ 96	$ 107

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor and to fund nonqualified benefit payments.

(b) Contribution in 2005 in excess of the required contribution to fully fund AEP's qualified pension plans by the end of 2005.

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to fund nonqualified benefit payments, 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 AEP's assets, including both AEP's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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)	
2006	$ 291	$ 117	$ (9)
2007	305	125	(10)
2008	316	133	(10)
2009	335	140	(11)
2010	344	148	(11)
Years 2011 to 2015, in Total	1,811	857	(65)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
	(in millions)					
Service Cost	$ 93	$ 86	$ 80	$ 42	$ 41	$ 42
Interest Cost	228	228	233	107	117	130
Expected Return on Plan Assets	(314)	(292)	(318)	(92)	(81)	(64)
Amortization of Transition (Asset) Obligation	-	2	(8)	27	28	28
Amortization of Prior Service Cost	(1)	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	55	17	11	25	36	52
Net Periodic Benefit Cost (Credit)	61	40	(3)	109	141	188
Capitalized Portion	(17)	(10)	(3)	(33)	(46)	(43)
Net Periodic Benefit Cost (Credit) Recognized as Expense	$ 44	$ 30	$ (6)	$ 76	$ 95	$ 145

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 2005, 2004 and 2003:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
	(in thousands)					
APCo	$ 7,391	$ 1,272	$ (5,202)	$ 20,005	$ 25,847	$ 33,747
CSPCo	2,143	(1,626)	(5,399)	8,202	11,050	14,684
I&M	9,463	4,460	(812)	13,524	17,259	22,999
KPCo	1,506	571	(566)	2,204	2,961	4,043
OPCo	4,825	(415)	(6,251)	15,442	20,975	28,143
PSO	295	2,795	(291)	6,989	8,449	9,885
SWEPCo	1,462	3,602	1,018	6,849	8,400	10,264
TCC	(880)	2,987	(123)	7,521	10,144	12,951
TNC	158	1,351	606	3,291	4,280	5,875

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2005	2004	2003	2005	2004	2003
	(in percentages)					
Discount Rate	5.50	6.25	6.75	5.80	6.25	6.75
Expected Return on Plan Assets	8.75	8.75	9.00	8.37	8.35	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 2005 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 to 8.75% for 2005. 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 increased to 8.37%.

The health care trend rate assumptions used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates	2005	2004
Initial	9.00%	10.0%
Ultimate	5.00%	5.0%
Year Ultimate Reached	2009	2009

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	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	263	(215)

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. 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 2005, 2004 and 2003:

	2005	2004	2003
		(in thousands)	
APCo	$ 6,780	$ 6,538	$ 6,450
CSPCo	2,929	2,723	2,745
I&M	7,892	7,262	7,616
KPCo	1,166	1,030	1,042
OPCo	5,962	5,688	5,719
PSO	2,915	2,731	2,350
SWEPCo	3,935	3,571	3,418
TCC	2,452	2,544	2,757
TNC	1,022	1,126	1,332

12. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business except AEGCo, which is 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 qualifying 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 influence that imperfections in marketplace transparency may cause pricing to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's 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 purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment 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 whether 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.

Depending on the exposure, the Registrant Subsidiaries designate a hedging instrument 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 earnings. 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) until the period the hedged item 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 immediately in earnings during the period of change.

Fair Value Hedging Strategies

Certain Registrant Subsidiaries enter into interest rate swap transactions in order to manage interest rate risk exposure. The interest rate swap transactions effectively modify exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant Subsidiaries record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged in Interest Expense. During 2005, 2004 and 2003, no Registrant Subsidiaries recognized hedge ineffectiveness related to these swaps.

Cash Flow Hedging Strategies

Certain Registrant Subsidiaries may 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 foreign currencies, the decline in value of future foreign currency cash flows 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. The impact of these hedges, which is immaterial, is included in Operating Expenses.

Certain Registrant Subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. Certain Registrant Subsidiaries enter into forward starting interest rate swap or treasury lock contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. Registrant Subsidiaries reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. During 2005 and 2003, certain Registrant Subsidiaries reclassified immaterial amounts into earnings due to hedge ineffectiveness. During 2004, certain Registrant Subsidiaries 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 and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative contracts to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2005, 2004 and 2003, certain Registrant Subsidiaries recognized immaterial amounts in earnings related to hedge ineffectiveness.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2003, 2004 and 2005:

	(in thousands)
APCo	
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)
Balance at December 31, 2004	(9,324)
Effective portion of changes in fair value	(4,515)
Reclasses from AOCI to net income	(2,582)
Ending Balance, December 31, 2005	$ (16,421)
CSPCo	
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)
Balance at December 31, 2004	1,393
Effective portion of changes in fair value	(71)
Reclasses from AOCI to net income	(2,181)
Ending Balance, December 31, 2005	$ (859)

I&M		
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)
Balance at December 31, 2004		(4,076)
Effective portion of changes in fair value		2,489
Reclasses from AOCI to net income		(1,880)
Ending Balance, December 31, 2005	$	(3,467)
KPCo		
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)
Balance at December 31, 2004		813
Effective portion of changes in fair value		81
Reclasses from AOCI to net income		(1,088)
Ending Balance, December 31, 2005	$	(194)
OPCo		
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)
Balance at December 31, 2004		1,241
Effective portion of changes in fair value		2,281
Reclasses from AOCI to net income		(2,767)
Ending Balance, December 31, 2005	$	755
PSO		
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)
Balance at December 31, 2004		400
Effective portion of changes in fair value		(1,168)
Reclasses from AOCI to net income		(344)
Ending Balance, December 31, 2005	$	(1,112)
SWEPCo		
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)
Balance at December 31, 2004		(820)
Effective portion of changes in fair value		(4,817)
Reclasses from AOCI to net income		(215)
Ending Balance, December 31, 2005	$	(5,852)

TCC		
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
Balance at December 31, 2004		657
Effective portion of changes in fair value		(635)
Reclasses from AOCI to net income		(246)
Ending Balance, December 31, 2005	$	(224)

TNC		
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
Balance at December 31, 2004		285
Effective portion of changes in fair value		(290)
Reclasses from AOCI to net income		(106)
Ending Balance, December 31, 2005	$	(111)

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2005 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 twelve months.

	(in thousands)	
APCo	$	3,414
CSPCo		713
I&M		1,050
KPCo		207
OPCo		(332)
PSO		632
SWEPCo		1,150
TCC		186
TNC		93

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, 2005 and 2004 are summarized in the following tables.

	2005		2004	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
AEGCo				
Long-term Debt	$ 44,828	$ 45,216	$ 44,820	$ 46,249
APCo				
Long-term Debt	2,151,378	2,134,973	1,784,598	1,822,687
CSPCo				
Long-term Debt	1,196,920	1,232,553	987,626	1,040,885
I&M				
Long-term Debt	1,444,940	1,456,000	1,312,843	1,349,614
Cumulative Preferred Stock Subject to Mandatory Redemption	-	-	61,445	61,637
KPCo				
Long-term Debt	486,990	484,834	508,310	521,776
OPCo				
Long-term Debt	2,199,670	2,250,708	2,011,060	2,092,645
Cumulative Preferred Stock Subject to Mandatory Redemption	-	-	5,000	5,016
PSO				
Long-term Debt	571,071	568,998	546,092	557,630
SWEPCo				
Long-term Debt	746,035	744,915	805,369	833,246
TCC				
Long-term Debt	1,853,496	1,916,511	1,907,294	2,013,546
TNC				
Long-term Debt	276,845	281,047	314,357	329,514

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. In 2004, TCC reported trusts in Assets Held for Sale – Texas Generation Plant 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	
	2005	2004	2005	2004
	(in thousands)			
Fair Value	$ 1,133,600	$ 1,053,400	$ -	$ 143,200
Cost Basis	988,500	936,500	-	107,000

	I&M			TCC		
	2005	2004	2003	2005	2004	2003
	(in thousands)					
Net Unrealized Gain (Loss)	$ 28,200	$ 34,500	$ 35,500	$ -	$ 6,400	$ 16,700

14. INCOME TAXES

The details of the Registrant Subsidiaries' income taxes before extraordinary loss and cumulative effect of accounting changes as reported are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2005					
Income Tax Expense (Credit)					
Current	$ 5,089	$ (1,915)	$ 44,968	$ 62,082	$ 2,803
Deferred	(1,666)	72,763	19,209	26,873	10,555
Deferred Investment Tax Credits	(3,532)	(4,659)	(2,717)	(7,725)	(1,222)
Total Income Tax as Reported	$ (109)	$ 66,189	$ 61,460	$ 81,230	$ 12,136

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2005					
Income Tax Expense (Credit)					
Current	$ 68,508	$ (14,510)	$ 44,156	$ 106,437	$ 24,426
Deferred	59,593	46,342	(4,942)	(91,387)	(4,578)
Deferred Investment Tax Credits	(3,123)	(1,347)	(4,292)	(2,609)	(1,271)
Total Income Tax as Reported	$ 124,978	$ 30,485	$ 34,922	$ 12,441	$ 18,577

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Year Ended December 31, 2004					
Income Tax Expense (Credit)					
Current	$ 5,442	$ 37,689	$ 57,140	$ 84,639	$ (2,870)
Deferred	(2,219)	47,585	13,395	(5,548)	12,774
Deferred Investment Tax Credits	(3,339)	(163)	(2,864)	(7,476)	(1,233)
Total Income Tax as Reported	$ (116)	$ 85,111	$ 67,671	$ 71,615	$ 8,671

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2004					
Income Tax Expense (Credit)					
Current	$ 75,883	$ (12,434)	$ 26,271	$ 123,304	$ 19,565
Deferred	23,329	22,034	12,782	16,490	4,236
Deferred Investment Tax Credits	(3,102)	(1,791)	(4,326)	(4,736)	(1,292)
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)		
Income Tax Expense (Credit)					
Current	$ 7,285	$ 83,803	$ 81,286	$ 63,473	$ (9,222)
Deferred	(5,838)	24,563	(4,514)	(14,894)	20,107
Deferred Investment Tax Credits	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
Total Income Tax as Reported	$ (1,907)	$ 105,220	$ 73,662	$ 41,148	$ 9,675

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Income Tax Expense (Credit)					
Current	$ 117,024	$ 54,268	$ 45,456	$ 90,986	$ 35,276
Deferred	24,482	(14,641)	9,942	19,393	(3,493)
Deferred Investment Tax Credits	(3,107)	(1,790)	(4,326)	(5,207)	(1,520)
Total Income Tax as Reported	$ 138,399	$ 37,837	$ 51,072	$ 105,172	$ 30,263

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.

Year Ended December 31, 2005	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Income	$ 8,695	$ 133,576	$ 136,960	$ 146,852	$ 20,809
Cumulative Effect of Accounting Changes	-	2,256	839	-	-
Income Taxes	(109)	66,189	61,460	81,230	12,136
Pretax Income	$ 8,586	$ 202,021	$ 199,259	$ 228,082	$ 32,945
Income Tax on Pretax Income at Statutory Rate (35%)	$ 3,005	$ 70,707	$ 69,741	$ 79,829	$ 11,531
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	757	11,257	1,614	19,492	1,644
Nuclear Fuel Disposal Costs	-	-	-	(3,413)	-
Allowance for Funds Used During Construction	(1,097)	(4,786)	(679)	(3,819)	(614)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(4,275)	(357)	(5,476)	(995)
Investment Tax Credits (net)	(3,532)	(4,659)	(2,717)	(7,725)	(1,222)
State and Local Income Taxes	723	2,223	448	6,598	778
Other	(339)	(4,278)	(6,590)	(4,653)	1,014
Total Income Taxes as Reported	$ (109)	$ 66,189	$ 61,460	$ 81,230	$ 12,136
Effective Income Tax Rate	N.M.	32.8%	30.8%	35.6%	36.8%

N.M. = Not Meaningful

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Year Ended December 31, 2005					
Net Income (Loss)	$ 245,844	$ 57,893	$ 73,938	$ (173,779)	$ 33,004
Extraordinary Loss	-	-	-	224,551	-
Cumulative Effect of Accounting Changes	4,575	-	1,252	-	8,472
Income Taxes	124,978	30,485	34,922	12,441	18,577
Pretax Income	$ 375,397	$ 88,378	$ 110,112	$ 63,213	$ 60,053
Income Tax on Pretax Income at Statutory Rate (35%)	$ 131,389	$ 30,932	$ 38,539	$ 22,125	$ 21,019
Increase (Decrease) in Income Tax resulting from the following items:					
Depreciation	5,201	(775)	(211)	(519)	(513)
Depletion	-	-	(3,150)	-	-
Investment Tax Credits (net)	(3,123)	(1,347)	(4,292)	(2,609)	(1,271)
State and Local Income Taxes	(5,437)	(1,387)	1,831	300	718
Other	(3,052)	3,062	2,205	(6,856)*	(1,376)
Total Income Taxes as Reported	$ 124,978	$ 30,485	$ 34,922	$ 12,441	$ 18,577
Effective Income Tax Rate	33.3%	34.5%	31.7%	19.7%	30.9%

*Includes $(3,900) of consolidated tax savings from parent.

	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)
Depletion	-	-	(2,100)	-	-
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)	(5,425)	(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%

N.M. = Not Meaningful

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
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)
Depletion	-	-	(2,100)	-	-
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	(1,079)	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%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each Registrant Subsidiary:

As of December 31, 2005	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Deferred Tax Assets	$ 61,315	$ 221,910	$ 76,785	$ 614,838	$ 26,806
Deferred Tax Liabilities	(84,932)	(1,174,407)	(575,017)	(950,102)	(261,525)
Net Deferred Tax Liabilities	$ (23,617)	$ (952,497)	$ (498,232)	$ (335,264)	$ (234,719)
Property Related Temporary Differences	$ (56,297)	$ (695,698)	$ (391,117)	$ (42,401)	$ (175,512)
Amounts Due From Customers For Future Federal Income Taxes	5,711	(93,171)	(6,053)	(28,714)	(24,720)
Deferred State Income Taxes	(3,987)	(108,455)	(9,409)	(36,352)	(25,950)
Transition Regulatory Assets	-	(7,428)	(50,719)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	8,944	473	1,922	120
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	32,018	-	-	21,303	-
Accrued Nuclear Decommissioning Expense	-	-	-	(214,126)	-
Deferred Fuel and Purchased Power	-	7,471	(39)	(1,200)	-
Deferred Cook Plant Restart Costs	-	-	-	-	-
Accrued Pensions	-	(48,649)	(40,460)	(28,443)	(6,488)
Nuclear Fuel	-	-	-	(8,040)	-
All Other (Net)	(1,062)	(15,511)	(908)	787	(2,169)
Net Deferred Tax Liabilities	$ (23,617)	$ (952,497)	$ (498,232)	$ (335,264)	$ (234,719)

As of December 31, 2005	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Deferred Tax Assets	$ 138,836	$ 50,570	$ 67,226	$ 146,877	$ 37,158
Deferred Tax Liabilities	(1,126,222)	(486,952)	(476,739)	(1,195,249)	(169,493)
Net Deferred Tax Liabilities	$ (987,386)	$ (436,382)	$ (409,513)	$ (1,048,372)	$ (132,335)
Property Related Temporary Differences	$ (789,885)	$ (336,743)	$ (321,810)	$ (240,361)	$ (121,192)
Amounts Due From Customers For Future Federal Income Taxes	(51,780)	4,231	(961)	7,216	3,892
Deferred State Income Taxes	(41,366)	(59,574)	(45,218)	(43,427)	(7,316)
Transition Regulatory Assets	(49,505)	-	14	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,983)	-
Nuclear Fuel	-	-	-	-	-
Deferred Income Taxes on Other Comprehensive Loss	(406)	681	3,300	620	271
Deferred Fuel and Purchased Power	-	(37,984)	(26,449)	(1,738)	(8,554)
Accrued Pensions	(52,450)	(32,387)	(29,041)	(41,894)	(17,698)
Provision for Refund	-	67	843	40,111	11,671
Regulatory Assets	7,340	-	(496)	(464,080)	(2,915)
Securitized Transition Assets	-	-	-	(231,587)	-
All Other (Net)	(9,334)	25,327	10,305	(3,173)	9,506
Net Deferred Tax Liabilities	$ (987,386)	$ (436,382)	$ (409,513)	$ (1,048,372)	$ (132,335)

As of December 31, 2004	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
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)
Nuclear Fuel	-	-	-	(15,485)	-
All Other (Net)	(1,050)	(17,960)	(13,137)	(10,038)	(4,830)
Net Deferred Tax Liabilities	$ (24,762)	$ (852,536)	$ (464,545)	$ (315,730)	$ (227,536)

As of Ended December 31, 2004	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
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)	$ (323,357)	$ (329,073)	$ (386,287)	$ (126,359)
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	21,740	2,141	(568)	1,565
Net Deferred Tax Liabilities	$ (943,465)	$ (384,090)	$ (399,756)	$ (1,247,111)	$ (138,465)

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies allocates 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.

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. These 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 Agent's 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 management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. As of December 31, 2005, Registrant Subsidiaries have total provisions for uncertain tax positions of approximately $28 million, excluding AEGCo. In addition, the Registrant Subsidiaries accrue 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.

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% (when fully phased-in in 2010) on a percentage of "qualified production activities income." For 2005 and for 2006, the deduction is 3% of qualified production activities income. The deduction increases to 6% 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. The FERC has issued an order that states the deduction is a special deduction that reduces the amount of income taxes due from energy sales. While the U.S. Treasury has issued proposed regulations on the calculation of the deduction, these proposed regulations lack clarity as to determination of qualified production activities income as it relates to utility operations. Management believes that the special deduction for 2006 will not materially affect our results of operations, cash flows, or financial condition.

On August 8, 2005 the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of Integrated Gasification Combined Cycle (IGCC) plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP has announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. The United States Treasury Department was to announce by February 6, 2006 the program whereby taxpayers could apply for and be allocated these credits. The Treasury Department has yet to define its program. Management cannot predict if AEP will be allocated any of these tax credits.

The Energy Tax Incentives Act of 2005 also changed the tax depreciation life for transmission assets from 20 years to 15 years. This act also allows for the accelerated amortization of atmospheric pollution control equipment placed in service after April 11, 2005 and installed on plants placed in service on or after January 1, 1976. This provision allows for tax amortization of the equipment over 84-months in lieu of taking a depreciation deduction over 20-years. This act also allows for the transfer ("poured-over") of funds held in non-qualifying nuclear decommissioning trusts into qualified nuclear decommissioning trusts. The tax deduction may be claimed, as the non-qualified funds are poured-over, the funds are poured-over over the remaining life of the plant. The earnings on funds held in a qualified nuclear decommissioning fund are taxed at a 20% federal rate as opposed to a 35% federal tax rate for non-qualified funds. Management believes that the tax law changes discussed in this paragraph will not materially affect our results of operations, cash flows, or financial condition.

After Hurricanes Katrina, Rita and Wilma in 2005, a series of tax acts were placed into law to aid in the recovery of the Gulf coast region. The Katrina Emergency Tax Relief Act of 2005 (enacted September 23, 2005) and the Gulf Opportunity Zone Act of 2005 (enacted December 21, 2005) contained a number of provisions to aid businesses and individuals impacted by these hurricanes. Management believes that the application of these tax acts will not materially affect our results of operations, cash flows, or financial condition.

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities that are not expected to reverse during the phase-out as follows in thousands:

Company	Other Regulatory Liabilities (a)	SFAS 109 Regulatory Asset, Net (b)	State Income Tax Expense (c)	Deferred State Income Tax Liabilities (d)
APCo	$ -	$ 10,945	$ 2,769	$ 13,714
CSPCo	15,104	-	-	15,104
I&M	-	5,195	-	5,195
KPCo	-	3,648	-	3,648
OPCo	41,864	-	-	41,864
PSO	-	-	706	706
SWEPCo	-	582	119	701
TCC	-	1,156	365	1,521
TNC	-	120	75	195

(a) The reversal of deferred state income taxes for the Ohio companies was recorded as a regulatory liability pending rate-making treatment in Ohio.
(b) Deferred state income tax adjustments related to those companies in which state income taxes flow through for rate-making purposes reduced the regulatory asset associated with the deferred state income tax liabilities.
(c) These amounts were recorded as a reduction to Income Tax Expense.
(d) Total deferred state income tax liabilities that reversed during 2005 related to Ohio law change.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 was approximately $1 million and $1 million for CSPCo and OPCo, respectively.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0% to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance polices; all of which will not have a material impact on future results of operations and cash flows.

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 Maintenance and Other Operation expense 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, 2005	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Lease Payments on Operating Leases	$ 77,872	$ 8,539	$ 6,194	$ 97,700	$ 1,735
Amortization of Capital Leases	284	6,273	3,313	6,681	1,519
Interest on Capital Leases	709	449	540	2,442	34
Total Lease Rental Costs	$ 78,865	$ 15,261	$ 10,047	$ 106,823	$ 3,288

Year Ended December 31, 2005	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Lease Payments on Operating Leases	$ 10,528	$ 5,658	$ 5,867	$ 5,594	$ 2,275
Amortization of Capital Leases	7,940	668	6,200	478	249
Interest on Capital Leases	2,275	93	2,738	60	34
Total Lease Rental Costs	$ 20,743	$ 6,419	$ 14,805	$ 6,132	$ 2,558

Year Ended December 31, 2004	AEGCo	APCo	CSPCo	I&M	KPCo
			(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

Year Ended December 31, 2004	OPCo	PSO	SWEPCo	TCC	TNC
			(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

Year Ended December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
			(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

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(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

Property, plant and equipment under capital leases and related obligations recorded on the Registrant Subsidiaries' balance sheets are as follows:

As of December 31, 2005	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Production	$ 12,316	$ 1,275	$ 7,104	$ 18,964	$ 436
Distribution	-	-	-	14,589	-
Other	349	36,792	16,059	38,568	9,128
Total Property, Plant and Equipment	12,665	38,067	23,163	72,121	9,564
Accumulated Amortization	438	23,185	13,609	28,145	6,396
Net Property, Plant and Equipment Under Capital Leases	$ 12,227	$ 14,882	$ 9,554	$ 43,976	$ 3,168
Obligations Under Capital Leases:					
Noncurrent Liability	$ 11,930	$ 9,292	$ 6,545	$ 38,645	$ 2,030
Liability Due Within One Year	297	5,600	3,031	5,331	1,138
Total Obligations Under Capital Leases	$ 12,227	$ 14,892	$ 9,576	$ 43,976	$ 3,168

As of December 31, 2005	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Production	$ 40,554	$ -	$ 14,270	$ -	$ -
Distribution	-	-	-	-	-
Other	37,867	3,378	65,014	2,072	1,045
Total Property, Plant and Equipment	78,421	3,378	79,284	2,072	1,045
Accumulated Amortization	39,912	844	36,803	694	321
Net Property, Plant and Equipment Under Capital Leases	$ 38,509	$ 2,534	$ 42,481	$ 1,378	$ 724
Obligations Under Capital Leases:					
Noncurrent Liability	$ 30,750	$ 1,778	$ 37,055	$ 888	$ 506
Liability Due Within One Year	9,174	756	5,490	490	218
Total Obligations Under Capital Leases	$ 39,924	$ 2,534	$ 42,545	$ 1,378	$ 724

As of December 31, 2004	AEGCo	APCo	CSPCo	I&M	KPCo
			(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 Equipment Under 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

As of 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

Future minimum lease payments consisted of the following at December 31, 2005:

Capital Leases	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
2006	$ 996	$ 6,741	$ 3,489	$ 9,182	$ 1,309
2007	987	4,057	2,519	15,403	1,065
2008	977	3,500	2,344	5,686	612
2009	968	1,381	1,334	4,290	251
2010	963	1,118	977	2,201	166
Later Years	17,036	293	4	20,768	89
Total Future Minimum Lease Payments	21,927	17,090	10,667	57,530	3,492
Less Estimated Interest Element	9,700	2,198	1,091	13,554	324
Estimated Present Value of Future Minimum Lease Payments	$ 12,227	$ 14,892	$ 9,576	$ 43,976	$ 3,168

Capital Leases	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2006	$ 10,080	$ 870	$ 8,498	$ 547	$ 249
2007	8,316	666	8,341	362	165
2008	6,215	497	8,228	291	144
2009	4,329	397	7,791	219	133
2010	3,700	272	3,871	106	87
Later Years	22,426	150	22,847	4	39
Total Future Minimum Lease Payments	55,066	2,852	59,576	1,529	817
Less Estimated Interest Element	15,142	318	17,031	151	93
Estimated Present Value of Future Minimum Lease Payments	$ 39,924	$ 2,534	$ 42,545	$ 1,378	$ 724

Noncancelable Operating Leases	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
2006	$ 77,474	$ 9,772	$ 4,110	$ 100,745	$ 1,820
2007	77,180	7,797	3,553	98,324	1,564
2008	77,178	6,286	2,934	95,815	1,256
2009	77,175	5,555	2,558	94,833	1,097
2010	77,023	4,572	2,002	91,467	1,020
Later Years	890,920	11,502	4,001	949,711	1,942
Total Future Minimum Lease Payments	$ 1,276,950	$ 45,484	$ 19,158	$ 1,430,895	$ 8,699

Noncancelable Operating Leases	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2006	$ 17,869	$ 6,223	$ 6,236	$ 5,848	$ 2,418
2007	16,920	5,639	5,748	4,972	2,061
2008	15,973	3,600	5,030	3,534	1,831
2009	15,003	3,049	4,286	3,037	1,933
2010	13,578	3,417	2,934	3,304	1,599
Later Years	65,561	6,348	6,382	3,838	2,367
Total Future Minimum Lease Payments	$ 144,904	$ 28,276	$ 30,616	$ 24,533	$ 12,209

Gavin Scrubber Financing Arrangement

In 1994, OPCo entered into an agreement with JMG, an unrelated special purpose entity. JMG was formed to design, construct, own and lease the Gavin Scrubber for the Gavin Plant 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, with a non-affiliated third party. For the first half of 2003, OPCo recorded operating lease payments related to the Gavin Scrubber as operating lease expense. After July 1, 2003, OPCo has recorded the depreciation, interest and other operating expenses of JMG and has eliminated JMG's rental revenues against OPCo's 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, 2005 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

Preferred Stock

Registrant Subsidiary	Par Value	Authorized Shares	Shares Outstanding at December 31, 2005	Call Price at December 31, 2005 (a)	Series	Redemption	December 31, 2005	December 31, 2004
							(in thousands)	
APCo	$ 0 (b)	8,000,000	177,836	$ 110.00	4.50%	Any time	$ 17,784	$ 17,784
CSPCo	25	7,000,000	-	-	-	-	-	-
CSPCo	100	2,500,000	-	-	-	-	-	-
I&M	25	11,200,000	-	-	-	-	-	-
I&M	100	(c)	55,369	106.125	4.125%	Any time	5,537	5,537
I&M	100	(c)	14,412	102.000	4.560%	Any time	1,441	1,441
I&M	100	(c)	11,055	102.728	4.120%	Any time	1,106	1,106
I&M	100	(c)	-	-	5.900%	1/1/2009	-	13,200
I&M	100	(c)	-	-	6.250%	4/1/2009	-	19,250
I&M	100	(c)	-	-	6.300%	7/1/2009	-	13,245
I&M	100	(c)	-	-	6.875%	4/1/2008	-	15,750
OPCo	25	4,000,000	-	-	-	-	-	-
OPCo	100	(d)	14,595	103.00	4.08%	Any time	1,460	1,460
OPCo	100	(d)	22,824	103.20	4.20%	Any time	2,282	2,282
OPCo	100	(d)	31,512	104.00	4.40%	Any time	3,151	3,151
OPCo	100	(d)	97,462	110.00	4.50%	Any time	9,746	9,748
OPCo	100	(d)	-	-	5.90%	1/1/2009	-	5,000
PSO	100	(e)	44,548	105.75	4.00%	Any time	4,455	4,455
PSO	100	(e)	8,069	103.19	4.24%	Any time	807	807
SWEPCo	100	(f)	7,386	103.90	4.28%	Any time	740	740
SWEPCo	100	(f)	1,907	102.75	4.65%	Any time	190	190
SWEPCo	100	(f)	37,703	109.00	5.00%	Any time	3,770	3,770
TCC	100	(g)	41,922	105.75	4.00%	Any time	4,192	4,192
TCC	100	(g)	17,476	103.75	4.20%	Any time	1,748	1,748
TNC	100	810,000	23,566	107.00	4.40%	Any time	2,357	2,357

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Stated value is $100 per share.
(c) I&M has 2,250,000 authorized $100 par value per share shares in total.
(d) OPCo has 3,762,403 authorized $100 par value per share shares in total.
(e) PSO has 700,000 authorized shares in total.
(f) SWEPCo has 1,860,000 authorized shares in total.
(g) TCC has 3,035,000 authorized shares in total.

Registrant	Series	Number of Shares Redeemed for the Year Ended December 31, 2005	2004	2003
APCo	4.50%	-	3	60
APCo	5.90%	-	22,100	25,000
APCo	5.92%	-	31,500	30,000
I&M	4.120%	-	175	-
I&M	5.90%	132,000	20,000	-
I&M	6.25%	192,500	-	-
I&M	6.30%	132,450	-	-
I&M	6.875%	157,500	-	15,000
OPCo	4.50%	20	41	23
OPCo	5.90%	50,000	22,500	-
PSO	4.00%	-	50	2
SWEPCo	5.00%	-	-	12
TCC	4.00%	-	5	11
TNC	4.40%	-	4	102

Long-term Debt

There are certain limitations on establishing liens against the Registrant Subsidiaries' assets under their respective indentures. None of the long-term debt obligations of the Registrant Subsidiaries have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2005 and 2004:

Registrant	Maturity	Weighted Average Interest Rate at December 31, 2005	Interest Rates at December 31, 2005	Interest Rates at December 31, 2004	December 31, 2005	December 31, 2004
INSTALLMENT PURCHASE CONTRACTS (a)					(In thousands)	
AEGCo	2025(b)	4.05%	4.05%	4.05%	$ 44,828	$ 44,820
APCo	2007-2024 (c)	4.57%	2.70%-6.05%	1.85%-6.05%	236,771	236,759
CSPCo	2038	3.27%	3.20%-3.35%	1.75%-2.00%	92,082	92,077
I&M	2009-2025 (d)	3.89%	2.625%-6.55%	1.75%-6.55%	311,267	311,230
OPCo	2014-2029	3.63%	3.10%-5.5625%	2.10%-6.375%	492,130	490,028
PSO	2014-2020	3.93%	3.15%-6.00%	1.75%-6.00%	46,360	46,360
SWEPCo	2011-2019	4.58%	3.10%-6.10%	1.70%-6.10%	177,678	177,879
TCC	2015-2030 (e)	3.95%	3.15%-6.125%	2.15%-6.125%	489,603	327,894
TNC	2020	6.00%	6.00%	6.00%	44,310	44,310
SENIOR UNSECURED NOTES						
APCo	2005-2035	5.05%	3.60%-6.60%	2.88%-6.60%	1,713,476	1,320,663
CSPCo	2005-2035	5.81%	4.40%-6.60%	4.40%-6.85%	1,004,838	795,549
I&M	2006-2032	5.88%	5.05%-6.45%	5.05%-6.45%	898,398	772,712
KPCo	2007-2032	5.34%	4.3148%-6.91%	4.31%-6.91%	427,790	428,310
OPCo	2008-2033	5.76%	4.85%-6.60%	4.85%-6.60%	1,181,869	983,008
PSO	2009-2032	5.29%	4.70%-6.00%	4.70%-6.00%	474,711	399,762
SWEPCo	2005-2015	5.09%	4.90%-5.375%	4.50%-5.375%	249,801	299,686
TCC	2005-2033	6.08%	5.50%-6.65%	3.00%-6.65%	548,042	797,863
TNC	2013	5.50%	5.50%	5.50%	224,385	224,295
FIRST MORTGAGE BONDS (f)						
APCo	2005-2025	6.80%	6.80%	6.80%-8.00%	99,987	224,662
PSO	2005	-	-	6.50%	-	49,970
SWEPCo	2006-2007	6.95%	6.20%-7.00%	6.20%-7.00%	95,951	96,024
TCC	2005-2008	7.125%	7.125%	6.625%-7.125%	18,581	84,344
TNC	2005-2007	7.75%	7.75%	6.375%-7.75%	8,150	45,752
NOTES PAYABLE - AFFILIATED						
APCo	2010	4.708%	4.708%	-	100,000	-
CSPCo	2010	4.64%	4.64%	4.64%	100,000	100,000
KPCo	2006-2015	6.08%	5.25%-6.501%	5.25%-6.501%	60,000	80,000
OPCo	2006-2015	4.29%	3.32%-5.25%	3.32%-5.25%	400,000	400,000
PSO	2006	3.35%	3.35%	3.35%	50,000	50,000
SWEPCo	2010	4.45%	4.45%	4.45%	50,000	50,000
TCC	2007	4.58%	4.58%	-	150,000	-
NOTES PAYABLE – NONAFFILIATED						
OPCo	2008-2009	7.09%	6.27%-7.49%	6.27%-7.49%	125,671	138,024
SWEPCo	2006-2012	5.56%	4.47%-7.03%	2.325%-7.03%	59,577	68,761
SECURITIZATION BONDS						
TCC	2007-2017	5.78%	5.01%-6.25%	3.54%-6.25%	647,270	697,193
NOTES PAYABLE TO TRUST						
SWEPCo	2043	5.25%	5.25%	5.25%	113,029	113,019
OTHER LONG-TERM DEBT						
APCo	2026	13.718%	13.718%	13.718%	2,504	2,514
I&M (g)	-	-	-	-	235,805	228,901

(a) Under the terms of the installment purchase contracts, each Registrant Subsidiary 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. For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Interest payments range from monthly to semi-annually.

(b) 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.

(c) The fixed rate bonds due 2007 and 2019 are subject to mandatory tender for purchase on November 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006.

(d) 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).

(e) Installment purchase contract maturing in 2029 provides for bonds to be tendered in 2006. Therefore, this installment purchase contract has been classified for payment in 2006.

(f) First mortgage bonds are secured by the first mortgage liens on Electric Property, Plant and Equipment. Certain supplemental indentures to the first mortgage liens contain 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, TCC's first mortgage bonds were defeased and in 2005, TNC's first mortgage bonds were defeased.

(g) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets of $264 million and $262 million related to this obligation are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds in its Consolidated Balance Sheets at December 31, 2005 and 2004, respectively.

At December 31, 2005, future annual long-term debt payments are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
2006	$ 45,000	$ 146,999	$ -	$ 364,469	$ 39,771
2007	-	324,445	-	50,000	322,393
2008	-	199,734	112,000	50,000	30,000
2009	-	150,017	-	45,000	-
2010	-	250,019	250,000	-	-
Later Years	-	1,091,930	842,245	937,805	95,000
Total Principal Amount	45,000	2,163,144	1,204,245	1,447,274	487,164
Unamortized Discount	(172)	(11,766)	(7,325)	(2,334)	(174)
Total	$ 44,828	$ 2,151,378	$ 1,196,920	$ 1,444,940	$ 486,990

	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
2006	$ 212,354	$ 50,000	$ 17,149	$ 152,900	$ -
2007	17,854	-	102,312	202,729	8,150
2008	55,188	-	5,906	68,688	-
2009	77,500	50,000	4,406	53,627	-
2010	200,000	150,000	54,406	56,575	-
Later Years	1,642,130	321,360	561,206	1,321,673	269,310
Total Principal Amount	2,205,026	571,360	745,385	1,856,192	277,460
Unamortized Premium/(Discount)	(5,356)	(289)	650	(2,696)	(615)
Total	$ 2,199,670	$ 571,071	$ 746,035	$ 1,853,496	$ 276,845

In February 2006, APCo issued $50,275,000 variable rate installment purchase contracts maturing in February 2036. In February 2006, an affiliate issued TCC a 5.14%, $125 million note due August 2007.

Dividend Restrictions

Under the Federal Power Act, the Registrants Subsidiaries can only pay dividends out of retained or current earnings unless they obtain prior FERC approval.

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. In addition, PSO and TCC had trusts that were deconsolidated in 2003 due to the implementation of FIN 46. The Junior Subordinated Debentures held in the trust for PSO and TCC were retired in 2004. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on the Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2005 and 2004, is reported as Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2005 and 2004, are reported as Notes Payable to Trust within Long-term Debt – Nonaffiliated.

The business trust is treated as a nonconsolidated subsidiary of its parent company. The only asset of the business trust is the subordinated debentures issued by its 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. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The Utility Money Pool participants' money pool activity and corresponding authorized limits for the years ended December 31, 2005 and 2004 are described in the following tables:

Year Ended December 31, 2005:

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, 2005	Authorized Short-Term Borrowing Limit
	(in thousands)					
AEGCo	$ 45,694	$ 9,305	$ 15,551	$ 4,272	$ (35,131)	$ 125,000
APCo	242,718	321,977	134,079	44,622	(194,133)	600,000
CSPCo	180,397	181,238	143,885	94,083	(17,609)	350,000
I&M	203,248	11,768	87,208	5,797	(93,702)	500,000
KPCo	9,964	35,779	2,969	12,653	(6,040)	200,000
OPCo	162,907	182,495	64,142	75,186	(70,071)	600,000
PSO	101,962	66,159	30,205	32,632	(75,883)	300,000
SWEPCo	55,756	188,215	17,657	34,490	(28,210)	350,000
TCC	320,508	120,937	109,463	39,060	(82,080)	600,000
TNC	13,606	119,569	10,930	58,067	34,286	250,000

Year Ended December 31, 2004:

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	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

The maximum and minimum interest rates for funds either borrowed or loaned to the Utility Money Pool for the years ended December 31, 2005 and 2004 were 4.49% and 1.63% and 2.24% and 0.89%, respectively. The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2005 and 2004 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Year Ended December 31, 2005	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Year Ended December 31, 2004	Average Interest Rate for Funds Loaned to the Utility Money Pool for Year Ended December 31, 2005	Average Interest Rate for Funds Loaned to the Utility Money Pool for Year Ended December 31, 2004
		(in percentage)		
AEGCo	3.27	1.47	3.17	1.91
APCo	3.40	1.68	3.15	1.48
CSPCo	3.95	1.50	3.03	1.69
I&M	3.43	1.45	2.12	1.93
KPCo	3.70	1.59	2.70	1.61
OPCo	3.86	1.29	2.57	1.46
PSO	3.37	1.38	3.56	1.80
SWEPCo	4.10	1.37	2.62	1.67
TCC	3.18	1.40	2.43	1.47
TNC	4.41	1.09	3.29	1.56

As of December 31, 2005, AEP had credit facilities totaling $2.5 billion to support its commercial paper program. As of December 31, 2005, AEP's 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 $25 million in January 2005 and the weighted average interest rate of commercial paper outstanding during the year was 2.50%. In September 2005, Moody's Investors Service upgraded AEP's commercial paper rating to Prime-2 from Prime-3.

At December 31, 2005 and 2004, OPCo had $10 million and $23 million, respectively, in outstanding commercial paper related to JMG, reflected as Short-term Debt – Nonaffiliated on OPCo's Consolidated Balance Sheets. The interest rate of the JMG commercial paper at December 31, 2005 and 2004 was 4.47% and 2.50%, respectively. 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 AEP's available liquidity.

Interest expense related to the Utility Money Pool is included in Interest Expense 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,		
	2005	2004	2003
		(in thousands)	
AEGCo	$ 418	$ 338	$ 289
APCo	2,830	1,136	147
CSPCo	280	32	732
I&M	2,854	1,127	313
KPCo	18	65	897
OPCo	1,056	51	2,332
PSO	637	486	1,218
SWEPCo	293	219	787
TCC	3,272	177	617
TNC	8	8	449

Interest income related to the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries' Financial Statements. Interest income earned from amounts advanced to the Utility Money Pool by Registrant Subsidiary were:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
AEGCo	$ 24	$ 1	$ 8
APCo	543	24	1,589
CSPCo	2,757	1,076	777
I&M	6	84	1,814
KPCo	287	177	-
OPCo	1,129	1,965	700
PSO	431	76	156
SWEPCo	649	649	662
TCC	66	1,445	589
TNC	1,897	587	164

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, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues 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.

AEP Credit's sale of receivables agreement expires on August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 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 APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Year Ended December 31, 2005	2004
	($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 5,925	$ 5,163
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 106	$ 80
Deferred Revenue from Servicing Accounts Receivable	$ 1	$ 1
Loss on Sale of Accounts Receivables	$ 18	$ 7
Average Variable Discount Rate	3.23 %	1.50 %
Retained Interest if 10% Adverse Change in Uncollectible Accounts	$ 103	$ 78
Retained Interest if 20% Adverse Change in Uncollectible Accounts	$ 101	$ 76

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	Face Value December 31, 2005	2004
	($ in millions)	
Customer Accounts Receivable Retained	$ 826	$ 830
Accrued Unbilled Revenues Retained	374	665
Miscellaneous Accounts Receivable Retained	51	84
Allowance for Uncollectible Accounts Retained	(31)	(77)
Total Net Balance Sheet Accounts Receivable	1,220	1,502
Customer Accounts Receivable Securitized	516	435
Total Accounts Receivable Managed	$ 1,736	$ 1,937
Net Uncollectible Accounts Written Off	$ 74	$ 86

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 $30 million and $25 million at December 31, 2005 and 2004, 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 company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the participant's Statements of Income.

The amount of factored accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

	As of December 31,	
	2005	2004
	(in millions)	
APCo	$ 77.1	$ 58.7
CSPCo	124.4	110.1
I&M	102.7	91.4
KPCo	38.7	34.4
OPCo	122.1	106.0
PSO	146.5	96.7
SWEPCo	100.4	72.0

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2005	2004	2003
		(in millions)	
APCo	$ 5.1	$ 3.9	$ 3.4
CSPCo	7.4	10.2	9.8
I&M	7.4	6.5	6.1
KPCo	2.9	2.6	2.4
OPCo	6.1	7.7	8.7
PSO	11.1	8.9	5.8
SWEPCo	8.3	5.8	4.9

17. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit" sections of Note 16.

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 company's "member-load-ratio," which is calculated monthly on the basis of each company's 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, 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 includes exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's 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 System's 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 deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally 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.

On February 10, 2006, AEP filed with the FERC a proposed amendment to the CSW Operating Agreement to remove TCC and TNC as parties to the agreement since, pursuant to Texas electric restructuring law, those companies exited, or are in the process of exciting, the generation and load-servicing businesses. AEP made a similar filing to remove those two companies as parties to the System Integration Agreement. The matter is pending before the FERC.

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies 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.

On November 1, 2005, AEP filed with the FERC a proposed amendment to the System Integration Agreement to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method would cause such profits to be allocated generally on the basis of the zone in which the underlying transactions occurred or originated. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006. The matter is pending before the FERC.

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 and Virginia, 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.

AEP East Companies and AEP West Companies Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2005, 2004 and 2003:

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2005						
Sales to East System Pool	$ 162,014	$ 70,165	$ 314,677	$ 49,791	$ 542,364	$ -
Direct Sales to East Affiliates	70,130	-	-	-	64,449	270,545
Direct Sales to West Affiliates	25,776	14,162	14,998	6,122	19,562	-
Natural Gas Contracts with AEPES	60,793	34,324	33,461	14,586	46,751	-
Other	3,620	5,759	2,896	304	8,726	-
Total Revenues	$ 322,333	$ 124,410	$ 366,032	$ 70,803	$ 681,852	$ 270,545

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2004						
Sales to East System Pool	$ 138,566	$ 69,309	$ 250,356	$ 36,853	$ 487,794	$ -
Direct Sales to East Affiliates	62,018	-	-	-	55,017	241,578
Direct Sales to West Affiliates	22,238	13,322	14,682	5,206	17,899	-
Natural Gas Contracts with AEPES	25,733	15,732	17,886	6,306	22,971	-
Other	3,573	6,384	3,386	352	10,676	-
Total Revenues	$ 252,128	$ 104,747	$ 286,310	$ 48,717	$ 594,357	$ 241,578

Related Party Revenues	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
			(in thousands)			
2003						
Sales to East System Pool	$ 136,581	$ 59,184	$ 238,538	$ 33,607	$ 490,896	$ -
Direct Sales to East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales to West Affiliates	27,978	16,437	17,691	6,432	21,780	-
Natural Gas Contracts with AEPES	39,010	21,971	24,082	8,877	29,065	-
Other	3,138	8,715	2,783	550	8,298	-
Total Revenues	$ 267,345	$ 106,307	$ 283,094	$ 49,466	$ 600,803	$ 232,955

Related Party Revenues	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2005				
Direct Sales to West Affiliates	$ 33,992	$ 61,555	$ -	$ 98
Other	5,686	3,853	14,973	47,066
Total Revenues	$ 39,678	$ 65,408	$ 14,973	$ 47,164

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	114,688	52,800
Total Revenues	$ 23,130	$ 68,854	$ 153,770	$ 55,386

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2005, 2004, and 2003:

Related Party Purchases	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
2005					
Purchases from East System Pool	$ 453,600	$ 362,959	$ 116,735	$ 95,187	$ 104,777
Direct Purchases from East Affiliates	-	-	189,382	81,163	12,113
Total Purchases	$ 453,600	$ 362,959	$ 306,117	$ 176,350	$ 116,890

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

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(in thousands)		
2005				
Purchases from East System Pool	$ 43,516	$ 36,573	$ -	$ -
Direct Purchases from East Affiliates	281	278	-	-
Direct Purchases from West Affiliates	61,564	34,060	-	23
Total Purchases	$ 105,361	$ 70,911	$ -	$ 23

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(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

Related Party Purchases	PSO	SWEPCo	TCC	TNC
		(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

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 income statements of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's 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 company's "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, 2005, 2004 and 2003:

	2005	2004	2003
		(In thousands)	
APCo	$ 8,900	$ (500)	$ -
CSPCo	34,600	37,700	38,200
I&M	(47,000)	(40,800)	(39,800)
KPCo	(3,500)	(6,100)	(5,600)
OPCo	7,000	9,700	7,200

The net charges (credits) shown above are recorded in Other Operation in the Registrant Subsidiaries' income statements.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated January 1, 1997 (TCA). The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with 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, 2005, 2004 and 2003:

	2005	2004	2003
		(In thousands)	
PSO	$ 3,500	$ 8,100	$ 4,200
SWEPCo	5,200	13,800	5,000
TCC	(3,800)	(12,200)	(3,600)
TNC	(4,900)	(9,700)	(5,600)

The net charges (credits) shown above are recorded in the Other Operation portion of the Registrant Subsidiaries' income statements.

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's East companies 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.

During 2004, CSPCo purchased approximately 330,000 tons of coal from AEP Coal. The coal was delivered (at CSPCo's expense) to the Conesville Plant for a price of $26.15 per ton. In 2003, AEP Coal and CSPCo were parties to a coal purchase agreement dated October 15, 2002. The agreement provided for CSPCo's purchase of up to 960,000 tons of coal to be delivered (at CSPCo's expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. During 2004 and 2003, CSPCo's purchases from AEP Coal totaled $9.5 million and $23.9 million, respectively. These purchases were recorded in Fuel on CSPCo's Consolidated Balance Sheets.

AEP Coal and CSPCo were parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, in 2004 and 2003 AEP Coal transferred coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivered the coal via trucks to either CSPCo's Conesville Preparation Plant or CSPCo's power plant for a rate of $1.25 per ton. During 2004 and 2003, CSPCo paid AEP Coal $1.0 million and $3.4 million, respectively. These transloading costs were recorded in Fuel on CSPCo's Consolidated Balance Sheets.

As a result of management's decision to exit our non-core businesses, AEP Coal, Inc. (AEP Coal) was sold in March 2004.

Coal Transactions with AEP Coal Marketing

AEP Coal Marketing, a wholly-owned subsidiary of AEP, enters into sale and purchase transactions with certain operating companies. The transactions are executed on a spot basis and are performed at cost for the operating companies' fuel requirements. During 2005 and 2004, the only transactions were immaterial purchases by I&M and OPCo from AEP Coal Marketing. During 2003, I&M's net coal inventory sales to AEP Coal Marketing totaled $11.4 million.

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' risk management liabilities at December 31,:

Company	2005	2004
	(in thousands)	
APCo	$ (12,318)	$ (23,736)
CSPCo	(7,142)	(13,654)
I&M	(7,294)	(15,266)
KPCo	(2,932)	(5,570)
OPCo	(9,810)	(19,065)
Total	$ (39,496)	$ (77,291)

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who purchase 100% of the available generating capacity from the plant through May 2006. The related purchases of gas managed by AEPES were as follows:

	Year Ended December 31,		
	2005	2004	2003
Company		(in thousands)	
APCo	$ 3,905	$ 1,230	$ 1,546
CSPCo	2,113	732	936
I&M	2,255	805	1,000
KPCo	924	286	363
OPCo	2,916	1,281	1,234
Total	$ 12,113	$ 4,334	$ 5,079

These purchases are reflected in Purchased Electricity for Resale in the Registrant Subsidiaries' income statements.

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 ends in December 2022.

Jointly-Owned Electric Utility Plants

APCo and OPCo jointly own two power plants. The costs of operating these facilities are apportioned between owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on its respective Consolidated Statements of Income. Each company's investment in these plants is included in Property, Plant and Equipment on its respective Consolidated Balance Sheets.

AEG and I&M jointly own one generating unit and jointly lease the other generating unit of the Rockport Plant. The costs of operating this facility are equally apportioned between AEG and I&M since each company has a 50% interest. Each company's share of costs is included in the appropriate expense accounts in its respective income statements. Each company's investment in these plants is included in Property, Plant and Equipment on its respective Consolidated Balance Sheets.

Cook Coal Terminal

In 2005, 2004 and 2003, Cook Coal Terminal, a division of OPCo, performed coal transloading services at cost for APCo and I&M. OPCo's revenues for these services are included in Other-Affiliated and its expenses are included in Other Operation on its Consolidated Statements of Income. The revenues were as follows:

	Year Ended December 31,		
	2005	2004	2003
Company	(in thousands)		
APCo	$ 1,770	$ 730	$ -
I&M	13,653	14,275	13,114

APCo and I&M recorded the cost of the transloading services in Fuel on their respective Consolidated Balance Sheets.

In addition, Cook Coal Terminal provided coal transloading services for Ohio Valley Electric Corporation (OVEC) in 2005. The revenue recorded by OPCo and reported as Other – Nonaffiliated on its Consolidated Statements of Income was $513 thousand in 2005. OVEC is 43.47% owned by AEP and CSPCo.

I&M Barging and Other Services

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as Other – Affiliated on its Consolidated Statements of 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,		
	2005	2004	2003
Company	(in millions)		
I&M – revenues	$ 43.1	$ 38.2	$ 31.9
AEGCo – expense	11.4	9.5	8.1
APCo – expense	18.5	13.0	12.3
KPCo – expense	0.1	0.1	0.1
OPCo – expense	2.5	4.9	4.3
MEMCO – expense (Nonutility subsidiary of AEP)	10.6	10.7	7.1

Services Provided by MEMCO

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 Other Operation. For the years ended December 31, 2005, 2004 and 2003, I&M recorded $14.1 million, $12.6 million and $8.8 million, respectively.

Gas Purchases from HPL

Prior to its sale in January 2005, HPL acquired physical gas in the spot market. The gas was then purchased by TCC and TNC at cost for their fuel requirements. These purchases are included in Fuel from Affiliates for Electricity Generation on TCC's and TNC's respective income statements. The purchases from HPL were as follows:

	Year Ended December 31,		
	2005	2004	2003
Company	(in thousands)		
TCC	$ -	$ 129,682	$ 195,527
TNC	42	45,767	44,197

OPCo Indemnification Agreement with AEP Resources

OPCo has an indemnification agreement with AEP Resources (AEPR), a nonutility subsidiary of AEP, whereby AEPR holds OPCo harmless from market exposure related to OPCo's Power Purchase and Sale Agreement dated November 15, 2000 with Dow Chemical Company. In 2005 and 2004, AEPR paid OPCo $29.6 million and $21.5 million, respectively, which is reported in OPCo's Other Operation in its Consolidated Statements of Income. See "Power Generation Facility – Affecting OPCo" section of Note 7 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 43.47% owned by AEP and CSPCo, for the years ended December 31, 2005, 2004 and 2003 were:

	Year Ended December 31,		
	2005	2004	2003
Company		(in thousands)	
APCo	$ 77,337	$ 62,101	$ 55,219
CSPCo	20,602	16,724	15,259
I&M	30,961	27,474	25,659
OPCo	66,680	55,052	50,995

The amounts shown above are included in Purchased Electricity for Resale in the Registrant Subsidiaries' respective Consolidated Statements of Income.

Purchased Power from Sweeny

On behalf of the AEP West companies CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, which is 50% owned by AEP. The PPA is for unit contingent power up to a maximum of 315 MW from January 1, 2005 through December 31, 2014. The delivery point for the power under the PPA is in TCC's system. The power is sold in ERCOT. The purchase of Sweeny power and its sale to nonaffiliates are shared among the AEP West companies under the CSW Operating Agreement. The purchases from Sweeny were:

	Year Ended December 31, 2005
Company	(in thousands)
PSO	$ 57,742
SWEPCo	50,618
TCC	4,560
TNC	27,804

The amounts shown above are recorded in Purchased Electricity for Resale in the Registrant Subsidiaries' respective income statements.

OPCo Coal Transfers

In 2005, OPCo sold 142,226 tons of coal from its Mitchell plant inventory to APCo for $5,960,328. The coal was sold at cost, based on a weighted average cost method of carrying inventory. APCo paid for the cost of transporting the coal from OPCo's facility to its delivery point at APCo's Amos plant. The amount above was transferred from Fuel on OPCo's Consolidated Balance Sheet to APCo's Consolidated Balance Sheet at the time of the sale.

In 2005, OPCo also sold 30,844 tons of coal from its Gavin plant inventory to OVEC for $745,191. The coal was sold at cost, based on a weighted average cost method of carrying inventory. OVEC paid for the cost of transporting the coal from OPCO's facility to its delivery point at OVEC's Kyger Creek plant. The coal inventory had been recorded in Fuel on OPCo's Consolidated Balance Sheet at the time of the sale.

Sales of Property

The Registrant Subsidiaries had sales of electric property for the years ended December 31, 2005, 2004 and 2003 as shown in the following table.

	2005 (in thousands)
APCo to I&M	$ 554
APCo to OPCo	637
I&M to APCo	1,135
I&M to OPCo	3,423
KPCo to OPCo	101
OPCo to APCo	1,057
OPCo to I&M	2,142

	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

The electric property amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

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. During the reporting periods, AEPSC and its billings were subject to regulation by 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 Subsidiary's 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:

		Company's Share December 31,			
		2005		2004	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)			
CSPCo					
W.C. Beckjord Generating Station (Unit No. 6)	12.5%	$ 15,681	$ 52	$ 15,531	$ 139
Conesville Generating Station (Unit No. 4)	43.5	85,162	7,583	85,036	654
J.M. Stuart Generating Station	26.0	266,136	35,461	209,842	60,535
Wm. H. Zimmer Generating Station	25.4	749,112	2,295	741,043	7,976
Transmission	(a)	62,553	1,344	62,287	3,744
Total		$ 1,178,644	$ 46,735	$ 1,113,739	$ 73,048
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6%	$ 86,051	$ 700	$ 85,834	$ 345
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2%	$ 237,941	$ 3,829	$ 237,741	$ 2,559
Flint Creek Generating Station (Unit No. 1)	50.0	94,261	2,494	93,887	756
Pirkey Generating Station (Unit No. 1)	85.9	459,513	10,447	456,730	2,373
Total		$ 791,715	$ 16,770	$ 788,358	$ 5,688
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8%	$ 39,656	$ 321	$ 39,464	$ 271
STP Generation Station (Units No. 1 and 2)	0.0	-	-	2,386,961	2,144
Total		$ 39,656	$ 321	$ 2,426,425	$ 2,415
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7%	$ 288,934	$ 2,165	$ 287,198	$ 1,418

(a) Varying percentages of ownership.
(b) Included in Assets Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets. STP was completed in May 2005. TCC owned 25.2% of STP at December 31, 2004.

The accumulated depreciation with respect to each Registrant Subsidiary's share of jointly-owned facilities is shown below:

	Year Ended December 31,	
	2005	2004
Company	(in thousands)	
CSPCo	$ 497,548	$ 464,136
PSO	54,401	52,679
SWEPCo	512,742	491,269
TCC (a)	19,765	991,410
TNC	117,963	110,763

(a) Included in Assets Held for Sale - Texas Generation Plants on TCC's 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, 2005					
Operating Revenues	$ 66,546	$ 557,695	$ 367,133	$ 457,559	$ 128,060
Operating Income	3,195	92,359	78,667	72,890	21,083
Income Before Cumulative Effect of Accounting Changes	2,516	46,672	47,468	39,669	9,885
Net Income	2,516	46,672	47,468	39,669	9,885
June 30, 2005					
Operating Revenues	$ 65,082	$ 497,102	$ 359,990	$ 457,560	$ 122,709
Operating Income	2,340	53,752	63,558	69,589	9,743
Income Before Cumulative Effect of Accounting Changes	2,073	24,213	34,651	35,593	2,446
Net Income	2,073	24,213	34,651	35,593	2,446
September 30, 2005					
Operating Revenues	$ 69,640	$ 570,122	$ 454,568	$ 515,079	$ 143,996
Operating Income	2,912	79,477	65,604	100,754	18,223
Income Before Cumulative Effect of Accounting Changes	2,239	37,372	34,225	53,012	7,727
Net Income	2,239	37,372	34,225	53,012	7,727
December 31, 2005					
Operating Revenues	$ 69,487	$ 551,354	$ 360,641	$ 462,404	$ 136,578
Operating Income	2,454	57,800	35,051	43,427	11,782
Income Before Cumulative Effect of Accounting Changes	1,867	27,575	21,455	18,578	751
Net Income	1,867	25,319	20,616	18,578	751

Quarterly Periods Ended:	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2005					
Operating Revenues	$ 655,154	$ 253,082	$ 247,211	$ 201,357	$ 118,907
Operating Income	151,434	7,113	29,163	30,284	15,817
Income Before Cumulative Effect of Accounting Changes	99,483	505	12,205	1,137	7,394
Net Income	99,483	505	12,205	1,137	7,394
June 30, 2005					
Operating Revenues	$ 650,999	$ 286,602	$ 332,851	$ 202,326	$ 114,704
Operating Income	123,901	32,435	37,363	42,922	20,160
Income Before Cumulative Effect of Accounting Changes	71,481	18,570	19,304	28,368	12,004
Net Income	71,481	18,570	19,304	28,368	12,004
September 30, 2005					
Operating Revenues	$ 687,140	$ 432,633	$ 474,283	$ 203,365	$ 126,097
Operating Income	99,437	85,387	88,135	63,399	36,924
Income Before Cumulative Effect of Accounting Changes	56,408	48,654	49,731	40,476	22,304
Net Income	56,408	48,654	49,731	40,476	22,304
December 31, 2005					
Operating Revenues	$ 641,256	$ 331,761	$ 351,034	$ 186,198	$ 99,180
Operating Income (Loss)	50,715	(6,919)	5,876	40,676	3,798
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Changes	23,047	(9,836)	(6,050)	(19,209)	(226)
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (a)	-	-	-	(224,551)	-
Net Income (Loss)	18,472	(9,836)	(7,302)	(243,760)	(8,698)

(a) See "Extraordinary Items" section of Note 2 and "Texas Restructuring" section of Note 6 for discussions of the extraordinary loss booked in the fourth quarter of 2005.

Quarterly Periods Ended:	AEGCo	APCo	CSPCo	I&M	KPCo
			(In thousands)		
March 31, 2004					
Operating Revenues	$ 55,282	$ 530,454	$ 365,395	$ 430,411	$ 114,579
Operating Income	2,175	128,656	82,888	85,259	25,282
Income Before 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	$ 466,750	$ 358,757	$ 423,060	$ 106,891
Operating Income	2,026	63,547	60,001	57,967	12,564
Income Before 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	$ 486,041	$ 391,612	$ 462,641	$ 113,785
Operating Income	2,990	77,988	90,359	94,636	13,968
Income Before 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	$ 474,601	$ 332,161	$ 425,373	$ 113,706
Operating Income	2,939	58,370	25,331	31,697	11,525
Income Before Cumulative Effect of Accounting Changes	2,105	27,494	11,814	11,636	4,066
Net Income	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	$ 604,165	$ 207,267	$ 236,537	$ 297,584	$ 116,945
Operating Income (Loss)	155,999	(6,938)	20,544	73,062	25,870
Income (Loss) Before 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	$ 577,282	$ 231,899	$ 269,325	$ 280,561	$ 117,734
Operating Income	87,439	18,632	55,671	25,176	16,730
Income (Loss) Before 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	$ 603,054	$ 356,741	$ 331,815	$ 359,440	$ 160,885
Operating Income	102,179	71,096	83,640	87,028	30,296
Income Before 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	$ 588,224	$ 251,913	$ 253,395	$ 275,264	$ 157,894
Operating Income	73,922	16	19,384	58,815	18,175
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes (a)	40,484	174	9,281	222,581	9,959
Extraordinary Loss on Stranded Cost Recovery, Net of Tax (b)	-	-	-	(120,534)	-
Net Income	40,484	174	9,281	102,047	9,959

(a) Carrying costs income on stranded cost recovery of $302 million was recorded in the fourth quarter of 2004.

(b) See "Extraordinary Items" section of Note 2 for a discussion of the extraordinary loss booked in the fourth quarter of 2004.

For each of the Registrant Subsidiaries, (excluding TCC for 2004 and 2005) there were no significant, nonrecurring events in the fourth quarter of 2005 or 2004.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the Registrant Subsidiaries through intercompany notes. AEP and its Registrant Subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The Registrant 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 AEP.

Dividend Restrictions

Under regulatory orders, the 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 Credit 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.

AEP Credit's sale of receivables agreement expires August 24, 2007. The sale of receivables agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2005, $516 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 APCo's accounts receivable are sold to AEP Credit.

Budgeted Construction Expenditures

Construction expenditures for Registrant Subsidiaries for 2006 are:

Company	Projected Construction Expenditures (in millions)
AEGCo	$ 14
APCo	943
CSPCo	343
I&M	311
KPCo	100
OPCo	1,070
PSO	279
SWEPCo	288
TCC	278
TNC	73

Significant Factors

Integration Gasification Combined Cycle (IGCC) Power Plants

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSP. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover, or refund, in distribution rates any difference between the Ohio companies' market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. As of December 31, 2005, we have deferred $7 million of pre-construction IGCC costs for the Ohio companies. These costs primarily relate to an agreement with GE Energy and Bechtel Corporation to begin the front-end engineering design process.

In January 2006, APCo filed an application with the WVPSC seeking authority to construct a 600MW IGCC electric generating unit in West Virginia. If built, the unit would be located next to APCo's Mountaineer Plant.

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 (Postretirement Plans). The Qualified Plans and Postretirement Plans are collectively "the Plans."

The following table shows the net periodic cost (credit) for AEP's Pension Plans and Postretirement Plans:

	2005	2004
	(in millions)	
Net Periodic Cost:		
Pension Plans	$ 61	$ 40
Postretirement Plans	109	141
Assumed Rate of Return:		
Pension Plans	8.75%	8.75%
Postretirement Plans	8.37%	8.35%

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 2005, of approximately 10%. AEP anticipates that the investment managers employed for the Plans will continue to generate long-term returns averaging 8.50%.

The expected long-term rate of return on the Plans' assets is based on AEP's targeted asset allocation and its expected investment returns for each investment category. AEP's assumptions are summarized in the following table:

	Pension		Other Postretirement Benefit Plans		
	2005 Actual Asset Allocation	2006 Target Asset Allocation	2005 Actual Asset Allocation	2006 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	66%	70%	68%	66%	10.00%
Fixed Income	25%	28%	30%	31%	5.25%
Cash and Cash Equivalents	9%	2%	2%	3%	3.50%
Total	100%	100%	100%	100%	

	Pension	Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.50%	8.00%

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. Because of a $320 million discretionary contribution to the Qualified Plans at the end of 2005, 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 2006. AEP believes that 8.50% 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 7.76% and 12.90% for the twelve months ended December 31, 2005 and 2004, 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, 2005, AEP had cumulative losses of approximately $37 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 is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's AA bond index was constructed but with a duration matching 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, 2005 under this method was 5.50% for the Pension Plans and 5.65% 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 8.50%, a discount rate of 5.50% and various other assumptions, AEP estimates that the pension costs for all pension plans will approximate $73 million, $76 million and $56 million in 2006, 2007 and 2008, respectively. AEP estimates Postretirement Plan costs will approximate $99 million, $102 million and $97 million in 2006, 2007 and 2008, 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 Management's Discussion and Analysis of Registrant Subsidiaries.

The value of AEP's Pension Plans' assets increased to $4.1 billion at December 31, 2005 from $3.6 billion at December 31, 2004. The Qualified Plans paid $263 million in benefits to plan participants during 2005 (nonqualified plans paid $10 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.2 billion at December 31, 2005 from $1.1 billion at December 31, 2004. The Postretirement Plans paid $118 million in benefits to plan participants during 2005.

For AEP's underfunded pension plans, the accumulated benefit obligation in excess of plan assets was $81 million and $474 million at December 31, 2005 and 2004, respectively. While AEP's non-qualified pension plans are unfunded, the qualified pension plans are fully funded as of December 31, 2005.

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 2005 and 2004, resulting in the following favorable changes, which do not affect earnings or cash flow:

	Decrease in Minimum Pension Liability	
	2005	2004
	(in millions)	
Other Comprehensive Income	$ (330)	$ (92)
Deferred Income Taxes	(175)	(52)
Intangible Asset	(30)	(3)
Other	4	(10)
Minimum Pension Liability	$ (531)	$ (157)

AEP made discretionary contributions of $626 million and $200 million in 2005 and 2004, respectively, 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.

The FASB's current pension and postretirement benefit accounting project could have a major negative impact on our debt to capital ratio in future years. The potential change could require the recognition of an additional minimum liability even for fully funded pension and postretirement benefit plan, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 smoothing deferral and amortization of net actuarial gains and losses. If adopted, this could require recognition of a significant net of tax accumulated other comprehensive income reduction to common equity. We cannot predict the effects of the final rule or its effective date.

Litigation

See discussion of the Environmental Litigation under "Environmental Matters."

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 and costs of replacement power in the event of a nuclear incident at the Cook Plant. 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

The Registrant Subsidiaries have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain power plants; and
- Possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change.

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units. All of these matters are discussed below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality, and control mobile and stationary sources of air emissions. The major CAA programs affecting power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as "national ambient air quality standards" or NAAQS.

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO_2 and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO_2 and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reductions of both SO_2 and NO_x would be achieved through a cap-and-trade program. The Federal EPA is currently reconsidering certain aspects of the final CAIR, and the rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which the Registrant

Subsidiaries' power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO_2 and NO_x emissions in order to comply with CAIR. The Federal EPA is currently reconsidering certain aspects of the final CAMR, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO_2 emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program has encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. The Registrant Subsidiaries continue to meet their obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and-trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the "Regional Haze" program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

The CAIR and CAMR programs described above will require significant additional investments, some of which are estimable. However, many of the rules described above are the subject of reconsideration by the Federal EPA, have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Management's estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and selected compliance alternatives. In short, management cannot estimate compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

APCo, CSPCo, KPCo and OPCo installed a total of 9,700 MW of selective catalytic reduction (SCR) technology to control NO_x emissions at their power plants over the past several years to comply with NO_x requirements in various SIPs. Additional NO_x requirements associated with CAIR and CAMR will result in additional investments between 2006 and 2010, estimated to be $191 million, including completion of SCRs on an additional 1900 MW of capacity. The amount of additional investment per Registrant Subsidiary follows:

	Estimated Investment (in millions)
APCo	$ 2
CSPCo	42
OPCo	137
PSO	1
SWEPCo	9

The Registrant Subsidiaries are complying with Acid Rain Program SO_2 requirements by installing scrubbers, other controls, and using alternate fuels. The Registrant Subsidiaries also use SO_2 allowances received through Acid Rain Program allocations, purchased at the annual Federal EPA auction, and purchased in the market. Decreasing allowance allocations, diminishing SO_2 allowance bank, and increasing allowance costs will require installation additional controls on the Registrant Subsidiaries' power plants. In addition, under CAIR and CAMR the Registrant Subsidiaries will be required to install additional controls by 2010. The Registrant Subsidiaries plan to install by 2010 additional scrubbers on 8,700 MW to comply with current, CAIR and CAMR requirements. The following table shows the estimated costs for additional scrubbers from 2006 to 2010 by Registrant Subsidiary:

	Cost of Additional Scrubbers (in millions)
APCo	$ 1,251
CSPCo	234
KPCo	308
OPCo	979
SWEPCo	18

The Registrant Subsidiaries will also incur additional operation and maintenance expenses during 2006 and subsequent years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Assuming that the CAIR and CAMR programs are implemented consistent with the provisions of the final federal rules, the Registrant Subsidiaries expect to incur additional costs for pollution control technology retrofits totaling approximately $1 billion between 2011 and 2020. The cost are highly uncertain due to the uncertainty associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR; (2) the actual performance of the pollution control technologies installed on each unit, (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. Management cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

The Registrant Subsidiaries will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through regulated rates (in regulated jurisdictions). The Registrant Subsidiaries 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.

Clean Water Act Regulation

In July 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen. The standards vary based on the water bodies from which the plants draw their cooling water. These rules will result in additional capital and operating expenses, which the Federal EPA estimated could be $193 million for the Registrant Subsidiaries plants. Any capital costs incurred to meet these standards will likely be incurred between 2008 and 2010. The Registrant Subsidiaries are required to undertake site-specific studies and may propose site-specific compliance or mitigation measures that could significantly change this estimate. These studies are currently underway, and the rule has been challenged in the courts. The following table shows the investment amount per Registrant Subsidiary.

	Estimated Compliance Investments (in millions)
APCo	$ 21
CSPCo	19
I&M	118
OPCo	31

Potential Regulation of CO_2 Emissions

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 in November 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. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO_2 emissions from power plants, but none has passed either house of Congress.

The Federal EPA has stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. While mandatory requirements to reduce CO_2 emissions at power plants do not appear to be imminent, the AEP System participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain special interest groups, has been consolidated with the Federal EPA case. Several similar complaints were filed against other nonaffiliated utilities in 1999 and 2000. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has been completed, but no decision has been issued.

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.

Courts that have considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, have reached different conclusions. Similarly, courts that have considered whether the activities at issue increased emissions from the power plants have reached different results. The Federal EPA has recently issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." That rule is being challenged in the courts. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability the Registrant Subsidiaries might have 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 Registrant Subsidiaries do not prevail, management believes the Registrant Subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If the Registrant Subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

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 Registrant 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 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 AEP's 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 the 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, AEGCo 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 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 regulated revenues from our customers 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 alsoestimated. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. Accrued unbilled revenue as of December 31, 2005 and 2004 is reflected as Accrued Unbilled Revenues on the accompanying Registrant Subsidiaries' Balance Sheets.

Unbilled electric utility revenues included in Revenue for the years ended December 31 were as follows:

	2005	2004	2003
		(in thousands)	
APCo	$ 14,024	$ 18,206	$ 1,876
CSPCo	(5,404)	283	(5,881)
I&M	1,783	(2,942)	10,722
KPCo	1,105	3,833	(448)
OPCo	14,689	(2,793)	(18,502)
PSO	494	2,789	984
SWEPCo	606	1,814	(6,996)
TCC	(164)	(1,579)	4,636
TNC	1,250	(1,160)	1,834

Assumptions and Approach Used – The monthly estimate for unbilled revenues is calculated by operating company as net generation less the current month's billed KWH plus the prior month's 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 AEP East companies. The annual load research study, based on a sample of accounts, is an additional verification of the unbilled estimate. The unbilled estimate is also adjusted annually, if necessary, 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% of the Accrued Unbilled Revenues on the Balance Sheets.

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, involve 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 into 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 as necessary 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 evaluations of long-lived assets may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. 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 Used – 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 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 of the Notes to Financial Statements of Registrant Subsidiaries, 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 divesting certain generation assets and their sales values can vary from the recorded fair value as described in Note 10 of the Notes to Financial Statements of Registrant Subsidiaries. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's 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, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan 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, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan 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, 2005 Benefit Obligations:				
Discount Rate	$ (198)	$ 207	$ (116)	$ 124
Salary Scale	30	(30)	4	(4)
Cash Balance Crediting Rate	(16)	17	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	112	(106)
Effect on 2005 Periodic Cost:				
Discount Rate	(10)	10	(10)	10
Salary Scale	6	(5)	1	(1)
Cash Balance Crediting Rate	3	(2)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(17)
Expected Return on Assets	(18)	18	(5)	5

New Accounting Pronouncements

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. In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 that provided additional implementation guidance. The Registrant Subsidiaries applied the principles of SAB 107 and the applicable FSPs in conjunction with their adoption of SFAS 123R. The Registrant Subsidiaries implemented SFAS 123R in the first quarter of 2006 using the modified prospective method. This method required recording compensation expense for all awards granted after the time of adoption and recognition of the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Implementation of SFAS 123R did not materially affect results of operations, cash flows or financial condition.

The Registrant Subsidiaries adopted FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47) during the fourth quarter of 2005. The Registrant Subsidiaries completed a review of their FIN 47 conditional ARO and concluded that they have legal liabilities for asbestos removal and disposal in general building and generating plants. The cumulative effect of certain retirement costs for asbestos removal related to regulated operations was generally charged to a regulatory liability. Certain Registrant Subsidiaries recorded an unfavorable cumulative effect for their nonregulated operations related to asbestos removal as follows:

	Cumulative Effect	
	Pretax Income (Loss)	Net of Tax Income (Loss)
	(in millions)	
APCo	$ (3.5)	$ (2.3)
CSPCo	(1.3)	(0.8)
OPCo	(7.0)	(4.6)
SWEPCo	(1.9)	(1.3)
TNC	(13.0)	(8.5)

EITF Issue 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty" focuses on two inventory exchange issues. Inventory purchase or sales transactions with the same counterparty should be combined under APB Opinion No. 29, "Accounting for Nonmonetary Transactions" if they were entered in contemplation of one another. Nonmonetary exchanges of inventory within the same line of business should be valued at fair value if an entity exchanges finished goods for raw materials or work in progress within the same line of business and if fair value can be determined and the transaction has commercial substance. All other nonmonetary exchanges within the same line of business should be valued at the carrying amount of the inventory transferred. This issue will be implemented beginning April 1, 2006 and is not expected to have a material impact on the financial statements.

-This page intentionally left blank.-

ATTACHMENT 2 TO AEP:NRC:6071-01

INDIANA MICHIGAN POWER COMPANY
PROJECTED CASH FLOW FOR THE YEAR 2006

Indiana Michigan Power Co.
2006 Forecasted Internal Cash Flow
$ Millions

	Projected 2006
Net Income	150.34
Less: Common and Preferred Dividends	40.34
	110.00
Adjustments:	
Depreciation and Amortization	106.93
Amortization of Deferred Operating Costs	77.61
Deferred Federal Income Taxes and Investment Tax Credits	(15.56)
Allowance for Equity Funds Used During Construction Debt and Equity	(16.51)
Deferred Property Taxes	(8.86)
Change in Other Non-current Assets	(99.87)
Change in Other Non-current Liabilities	0.73
Changes in Working Capital	(15.65)
Total Adjustments	28.82
Internal Cash Flow	138.82