LARGE FILING SEPARATOR SHEET

CASE NUMBER: 08-917-EL-SSO
08-918-EL-SSO

FILE DATE: 12/17/2008

SECTION: (Part 1 of 2)

NUMBER OF PAGES: 202

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Exhibits for Transcript filed electronically filed 12/17/2008

FILE

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets. : Case No. 08-917-EL-SSO

In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan. : Case No. 08-918-EL-SSO

- - -

PROCEEDINGS

before Ms. Kimberly W. Bojko and Ms. Greta See, Hearing Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, called at 9:00 a.m. on Wednesday, December 3, 2008.

- - -

VOLUME XI

- - -

ARMSTRONG & OKEY, INC.
185 South Fifth Street, Suite 101
Columbus, Ohio 43215-5201
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EXHIBITS - TRANSCRIPT FILED ELECTRONICALLY

PUCO EXHIBIT FILING

Date of Hearing: 12/3/08

Case No. 08-917-EL-SSO | 08-918-EL-SSO

PUCO Case Caption: In the Matter of

Columbus Southern Power Company

Ohio Power Company

List of exhibits being filed:

Volume XI

Companies' Exs. 2B - 2C - 2D

IEU Exs. 3 → 9

Reporter's Signature: Maria DiPaolo Jones

Date Submitted: 12/9/08

Companies Ex. 2B

Direct Testimony
J. Craig Baker
Errata Sheet

1. Table of Contents
   Strike "Modification of Corporate Separation Plan and" from Page 35 insert "Modification of Corporate Separation Plan and" to Page 40.

2. Page 13 – OP Estimated Full Requirements table on the Losses Line a) change OP residential from $1.28 to $4.46 and b) change OP Commercial from $4.46 to $1.28.

3. Page 25 – Line 11 and 12 delete the sentence "This position represents another advantage of the Companies' ESP in comparison with an MRO."

4. Page 25 – Line 11 after "SSO rates" insert the following question and answer: Q. Are the environmental capital additions projected to be made in 2009-2011, as shown in Mr. Nelson's exhibit PJN-8, the basis for the proposed automatic increases to the non-FAC portion of the standard service offer? A. The Companies are proposing to increase the non-FAC portion of the standard service offer, adjusted to reflect the recovery of the 2009 carrying costs associated with the 2001-2008 environmental investments, by three percent a year for CSP and by seven percent a year for OPCO. Regarding the non-FAC portion annual increase, which is not intended to be a cost-of-service increase, a portion of that increase will support the carrying costs associated with the 2009-2011 additional environmental investment. The remainder of the annual automatic adjustments will support cost increases related to inflationary factors during the three-year ESP period as well as unanticipated non-mandated generation-related cost increases.

5. Page 26 – Line 11 after "notice." insert "By presently locking in the SSO price for the entire three-year period of the ESP, the Companies take on the risk of incurring costs associated with ensuring capacity during the entire three-year period of the ESP only to lose customers when market prices fall below the SSO.

6. Page 26 – Line 15 after "SSO)." insert "The proposed POLR charge is a quantification of both risk components."

7. Page 32 – In the table at the top of the Page under the "4) Interest Rate" Column delete "the 3 year Treasury Note" insert in its place "LIBOR"

8. Page 33 – Line 23 – delete the word "the" between "transferring" and "risk" and replace it with "that portion of the."

EXHIBIT JCB-2

REVISED

	Columbus Southern Power Company				Ohio Power Company			
	2009	2010	2011	Total	2009	2010	2011	Total
Estimated Cost of Market Rate Option								
MWH Load to be Purchased under 10%/20%/30% MRO	2,271,512	4,543,023	6,814,535		2,815,095	5,630,189	8,445,284	
Estimated Market Price ($/MWH)	$88.15	$88.15	$88.15		$85.32	$85.32	$85.32	
Estimated Purchase Cost of 10%/20%/30%	$200	$400	$601	$1,201	$240	$480	$721	$1,441
2001 - 2008 Incremental Environmental (90%/80%/70%)	$23	$21	$18	$62	$76	$67	$59	$202
POLR (90%/80%/70%)	~~$97~~ $84	~~$87~~ $75	~~$78~~ $66	~~$260~~ $225	~~$55~~ $19	~~$49~~ $17	~~$43~~ $15	~~$146~~ $51
Estimated Cost of 10%/20%/30% Market Rate Option	~~$321~~ **$308**	~~$508~~ **$496**	~~$695~~ **$684**	~~$1,523~~ **$1,488**	~~$371~~ **$335**	~~$506~~ **$565**	~~$822~~ **$794**	~~$1,730~~ **$1,694**
Estimated Cost of Companies' ESP								
Estimated Purchase Cost of 5%/10%/15%	$100	$200	$300	$601	$120	$240	$360	$721
Estimate Purchase Cost of								
2001 - 2008 Incremental Environmental	$26	$26	$26	$78	$84	$84	$84	$252
POLR	~~$108~~ $94	~~$108~~ $94	~~$108~~ $94	~~$325~~ $281	~~$61~~ $21	~~$61~~ $21	~~$61~~ $21	~~$183~~ $64
Annual 3%/7% non-FAC Increase	$14	$29	$44	$87	$42	$86	$134	$263
Annual 7%/6.5% Distribution Increase	$24	$50	$77	$150	$21	$44	$68	$133
Estimated Cost of Companies' ESP	~~$272~~ $258	~~$413~~ $398	~~$556~~ $541	~~$1,240~~ $1,197	~~$328~~ $288	~~$515~~ $476	~~$707~~ $668	~~$1,551~~ $1,432
Estimated Benefit of Companies' ESP	~~$49~~ **$50**	~~$95~~ **$98**	~~$130~~ **$144**	~~$283~~ **$292**	~~$43~~ **$47**	~~$81~~ **$89**	~~$115~~ **$127**	~~$238~~ **$262**

COMPANIES' EX. 2C

AEP OHIO'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMER COUNSEL
INTERROGATORY REQUESTS
FOURTH SET
CASE NO. 08-917-EL-SSO & CASE NO. 08-918-EL-SSO

INTERROGATORY REQUEST NO. 4-109.

What were the assumptions made in the Black-Scholes Model for:

a. the current price of the underlying stock?
b. the exercise price and the basis of the assumption?
c. the risk-free interest rate and the basis of the assumption?

RESPONSE:

a. The current price of the underlying stock is equivalent to the market price of electricity. Consistent with the context of the Company's ESP, the relevant price of power was the price of 'full-requirements' power for the calendar years 2009 through 2011 period, which in order to maintain consistency in our calculations, the market price of the calendar years 2009 through 2011 period power used in the Black-Scholes model was the same price as calculated by our competitive benchmark model presented on pages 7-13 of Witness Baker's direct testimony.

b. The exercise price used in the Black-Scholes model for all three years was the year one amount of the Company's proposed ESP filing in order to arrive at a conservative option price.

c. The risk-free interest rate was determined by taking the average of the LIBOR rate for the calendar years 2009 through 2011 period that was being priced. LIBOR was selected as an appropriate measure because of its wide financial use as a 'risk-free' proxy and because of the widely available nature of its quotes.

Prepared by: J. C. Baker

COMPANIES' EX. 2D

AEP OHIO'S RESPONSE TO
OHIO ENERGY GROUP'S
DISCOVERY REQUEST
THIRD SET
CASE NO. 08-917-EL-SSO
CASE NO. 08-918-EL-SSO

INTERROGATORY REQUEST NO. 3-5

With regard to Mr. Baker's proposed POLR revenue requirements of $108.2 million for CSP and $60.9 million for OPCO, please provide all supporting work papers used to develop these costs, including all spreadsheets with formulas intact.

RESPONSE

Please see Attachment 3-5 (1) and 3-5 (2) for the requested workpapers to support the POLR revenue requirements of $108.2 million for CSP and $60.9 million for OPCO.

Prepared by: J. C. Baker

Prepared by: J. C. Baker

asofdate	curvedate	zero_cc	df
7/24/2008	1/15/2009	3.1%	0.985253494
7/24/2008	2/15/2009	3.2%	0.982269901
7/24/2008	3/15/2009	3.2%	0.979685835
7/24/2008	4/15/2009	3.2%	0.976777579
7/24/2008	5/15/2009	3.3%	0.973916235
7/24/2008	6/15/2009	3.3%	0.970911534
7/24/2008	7/15/2009	3.3%	0.9679578
7/24/2008	8/15/2009	3.4%	0.965000612
7/24/2008	9/15/2009	3.4%	0.962128394
7/24/2008	10/15/2009	3.4%	0.959339757
7/24/2008	11/15/2009	3.4%	0.956448927
7/24/2008	12/15/2009	3.4%	0.953642537
7/24/2008	1/15/2010	3.4%	0.950733627
7/24/2008	2/15/2010	3.4%	0.947815733
7/24/2008	3/15/2010	3.4%	0.945172607
7/24/2008	4/15/2010	3.4%	0.942237992
7/24/2008	5/15/2010	3.5%	0.939389866
7/24/2008	6/15/2010	3.5%	0.936438487
7/24/2008	7/15/2010	3.5%	0.933574397
7/24/2008	8/15/2010	3.5%	0.930387164
7/24/2008	9/15/2010	3.5%	0.927010748
7/24/2008	10/15/2010	3.6%	0.923708869
7/24/2008	11/15/2010	3.6%	0.920261878
7/24/2008	12/15/2010	3.6%	0.916892621
7/24/2008	1/15/2011	3.7%	0.913376965
7/24/2008	2/15/2011	3.7%	0.909827153
7/24/2008	3/15/2011	3.7%	0.906591934
7/24/2008	4/15/2011	3.7%	0.902978512
7/24/2008	5/15/2011	3.8%	0.899450527
7/24/2008	6/15/2011	3.8%	0.895773281
7/24/2008	7/15/2011	3.8%	0.892184495
7/24/2008	8/15/2011	3.9%	0.888672707
7/24/2008	9/15/2011	3.9%	0.88530904
7/24/2008	10/15/2011	3.9%	0.882042568
7/24/2008	11/15/2011	3.9%	0.878655752
7/24/2008	12/15/2011	3.9%	0.875367315
		3.5%	

IEU Ex. 3

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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Indicate by check mark if the registrants with respect to American Electric Power Company, Inc. and Appalachian Power Company, is each a well-known seasoned issuer, as defined in Rule 405 on the Securities Act. Yes ☒ No. ☐

Indicate by check mark if the registrants with respect to Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act. Yes ☐ No. ☒

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

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

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

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, or non-accelerated filers. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act. Yes ☐ No. ☒

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

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

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

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

Registrant	Title of each class
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value 4.65% Cumulative Preferred Stock, Non-Voting, $100 par value 5.00% Cumulative Preferred Stock, Non-Voting, $100 par value

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2007, the last trading date of the registrants' most recently completed second fiscal quarter	Number of shares of common stock outstanding of the registrants at December 31, 2007
American Electric Power Company, Inc.	$17,979,507,421	400,426,704 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

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

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

Documents Incorporated By Reference

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2007: American Electric Power Company, Inc. Appalachian Power Company Columbus Southern Power Company Indiana Michigan Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2008 Annual Meeting of Shareholders.	Part III
Portions of Information Statements of the following companies for 2008 Annual Meeting of Shareholders: Appalachian Power Company Ohio Power Company	Part III

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

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

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP
AEP or parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo
AEP Power Pool	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEPSC	American Electric Power Service Corporation, a service company subsidiary of AEP
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries
AEP West companies	PSO, SWEPCo, TCC and TNC
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation
AFUDC	Allowance for funds used during construction (the net cost of borrowed funds, and a reasonable rate of return on other funds, used for construction under regulatory accounting)
ALJ	Administrative law judge
APCo	Appalachian Power Company, a public utility subsidiary of AEP
APSC	Arkansas Public Service Commission
Buckeye	Buckeye Power, Inc., an unaffiliated corporation
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
Cook Plant	The Donald C. Cook Nuclear Plant (2,143 MW), owned by I&M, and located near Bridgman, Michigan
CSPCo	Columbus Southern Power Company, a public utility subsidiary of AEP
CSW	Central and South West Corporation, a public utility holding company that merged with AEP in June 2000.
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, originally by and among PSO, SWEPCo, TCC and TNC, currently by and between PSO and SWEPCO governing generating capacity allocation. AEPSC acts as the agent for the parties.
DOE	United States Department of Energy
Dow	The Dow Chemical Company, and its affiliates collectively, unaffiliated companies
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
Duke Carolina	Duke Energy Carolinas, LLC
Duke Indiana	Duke Energy Indiana, Inc.
Duke Ohio	Duke Energy Ohio, Inc.
EMF	Electric and Magnetic Fields
EPA	United States Environmental Protection Agency
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
FPA	Federal Power Act
I&M	Indiana Michigan Power Company, a public utility subsidiary of AEP
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants
IURC	Indiana Utility Regulatory Commission
KPCo	Kentucky Power Company, a public utility subsidiary of AEP
LLWPA	Low-Level Waste Policy Act of 1980
Lawrenceburg Plant	A 1,146 MW gas-fired unit owned by AEGCo and located near Lawrenceburg, Indiana

Abbreviation or Acronym	Definition
LPSC	Louisiana Public Service Commission
MEMCO	AEP MEMCO LLC, an inland river transportation subsidiary operating primarily on the Ohio, Illinois, and Lower Mississippi rivers
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NOx	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff, filed with FERC
OCC	Corporation Commission of the State of Oklahoma
Ohio Act	Ohio electric restructuring legislation
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 43.47% equity interest
PJM	PJM Interconnection, L.L.C., a regional transmission organization
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Texas retail electricity provider
Rockport Plant	A generating plant owned and partly leased by AEGCo and I&M (two 1,300 MW, coal-fired) located near Rockport, Indiana
RSPs	The rate stabilization plans of CSPCo and OPCo, approved by the PUCO, which, among other things, address default generation service rates from January 1, 2006 through December 31, 2008
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poor's Ratings Service
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SWEPCo	Southwestern Electric Power Company, a public utility subsidiary of AEP
TCA	Transmission Coordination Agreement dated January 1, 1997 by and among, PSO, SWEPCo, TCC, TNC and AEPSC, which allocated costs and benefits through September 2005 in connection with the operation of the transmission assets of the four public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
TEA	Transmission Equalization Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
Tractebel	Tractebel Energy Marketing, Inc.
TVA	Tennessee Valley Authority
VSCC	Virginia State Corporation Commission
WPCo	Wheeling Power Company, a public utility subsidiary of AEP
WVPSC	West Virginia Public Service Commission

FORWARD-LOOKING INFORMATION

This report made by the registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although the registrants 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 and performance 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 (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates.
- 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 we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within RTOs.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust.
- 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.

The registrants expressly disclaim any obligation to update any forward-looking information.

PART I

ITEM 1. BUSINESS

GENERAL

OVERVIEW AND DESCRIPTION OF SUBSIDIARIES

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

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio, the ERCOT area of Texas and, through 2008, Virginia has caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

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

At December 31, 2007, the subsidiaries of AEP had a total of 20,861 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 956,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2007, APCo and its wholly owned subsidiaries had 2,497 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 746,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2007, CSPCo had 1,265 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

I&M (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 583,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2007, I&M had 2,687 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. This lease currently extends through February 2010. In addition to its AEP System interconnections, I&M is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2007, KPCo had 471 employees. In addition to its AEP System interconnections, KPCo is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 47,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. At December 31, 2007, Kingsport Power Company had 57 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2007, OPCo had 2,351 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PSO (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 525,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2007, PSO had 1,255 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods. In addition to its AEP System interconnections, PSO is interconnected with Ameren Corporation, Empire District Electric Company, Oklahoma Gas and Electric Company, Southwestern Public Service Company and Westar Energy, Inc. PSO is a member of SPP.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 467,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2007, SWEPCo had 1,578 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 753,000 retail customers through REPs in southern Texas. Under the Texas Act, TCC has completed the final stage of exiting the generation business and has sold all of its generation assets. At December 31, 2007, TCC had 1,195 employees. Among the principal industries served by TCC are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the transmission and distribution of electric power to approximately 184,000 retail customers through REPs in west and central Texas. TNC's remaining generating capacity that is not deactivated has been transferred to an affiliate at TNC's cost pursuant to a 20-year agreement. At December 31, 2007, TNC had 373 employees. Among the principal industries served by TNC are agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. At December 31, 2007, WPCo had 61 employees.

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

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2007, AEPSC had 6,151 employees.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2007 are as follows:

Description	AEP System(a)	APCo	CSPCo	I&M
	(in thousands)			
UTILITY OPERATIONS:				
Retail Sales				
Residential Sales	$ 3,991,000	$ 787,710	$ 682,184	$ 418,953
Commercial Sales	2,906,000	387,323	619,396	328,754
Industrial Sales	2,674,000	540,968	272,673	360,341
PJM Net Charges	(131,000)	(43,803)	(24,433)	(24,613)
Provision for Rate Refund	(4,000)	(12,996)	-	-
Other Retail Sales	192,000	49,464	5,441	6,209
Total Retail	9,628,000	1,708,666	1,555,261	1,089,644
Wholesale				
Off-System Sales	2,003,000	597,556	323,934	591,893
Transmission	145,000	(17,355)	(11,492)	5,603
Total Wholesale	2,148,000	580,201	312,442	597,496
Other Electric Revenues	216,000	44,581	25,342	21,058
Other Operating Revenues	109,000	10,755	7,155	27,367
Sales To Affiliates	-	263,066	143,112	307,627
Total Utility Operating Revenues	12,101,000	2,607,269	2,043,312	2,043,192
OTHER	1,279,000	-	-	-
TOTAL REVENUES	$ 13,380,000	$ 2,607,269	$ 2,043,312	$ 2,043,192

Description	OPCo	PSO	SWEPCo
	(in thousands)		
UTILITY OPERATIONS:			
Retail Sales			
Residential Sales	$ 592,348	$ 482,963	$ 423,504
Commercial Sales	385,783	352,155	367,280
Industrial Sales	629,589	307,833	287,590
PJM Net Charges	(28,901)	-	-
Provision for Rate Refund	-	-	(16,877)
Other Retail Sales	9,258	88,346	7,561
Total Retail	1,588,077	1,231,297	1,069,058
Wholesale			
Off-System Sales	415,726	62,968	258,383
Transmission	(13,320)	16,641	37,351
Total Wholesale	402,406	79,609	295,734
Other Electric Revenues	29,149	11,013	63,821
Other Operating Revenues	14,823	4,525	1,747
Sales to Affiliates	779,757	69,106	53,102
Total Utility Operating Revenues	2,814,212	1,395,550	1,483,462
OTHER	-	-	-
TOTAL REVENUES	$ 2,814,212	$ 1,395,550	$ 1,483,462

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated for the year ended December 31, 2007.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt is also used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and a $50 million cross-acceleration provision. At December 31, 2007, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency would be considered an immediate termination event. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2007 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEP's credit agreements.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as leasing arrangements, including the leasing of coal transportation equipment and facilities.

Credit Ratings

AEP's senior unsecured debt is rated Baa2 by Moody's and BBB by S&P and Fitch. AEP's commercial paper is rated Prime-2 by Moody's, A2 by S&P and F2 by Fitch. There were no changes in the ratings or rating outlook for AEP by Moody's, S&P or Fitch during 2007. In February 2008 Fitch downgraded the senior unsecured debt rating of PSO to BBB+ with stable outlook. Fitch downgraded the senior unsecured debt rating of TCC (to BBB+) in April 2007 and placed it on negative outlook until November 2007, when Fitch restored its stable outlook. Fitch revised TNC's outlook from negative to stable in April 2007. Moody's placed the senior unsecured debt rating of APCo, OPCo, SWEPCo and TCC on negative outlook in January 2008. Moody's assigns the following ratings to the senior unsecured debt of these companies: APCo Baa2, OPCo A3, SWEPCo Baa1 and TCC Baa2. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2007 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants.

ENVIRONMENTAL AND OTHER MATTERS

General

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

- Global climate change and legislative responses to it, including limitations on CO_2 emissions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters – Potential Regulation of CO_2 and GHG Emissions.*
- The CAA and CAAA and state laws and regulations (including State Implementation Plans) that require compliance, obtaining permits and reporting as to air emissions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters - Clean Air Act Requirements* and *Estimated Air Quality Environmental Investments.*

- Litigation with the federal and certain state governments and certain special interest groups regarding regulated air emissions and/or whether emissions from coal-fired generating plants cause or contribute to global climate changes. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters - Environmental Litigation* and Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2007 Annual Reports, for further information.

- Rules issued by the EPA and certain states that require substantial reductions in SO_2, mercury and NOx emissions, which have compliance dates that take effect periodically through as late as 2018. AEP is installing (and has installed) emission control technology and is taking other measures to comply with required reductions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters - Clean Air Act Requirements* and *Estimated Air Quality Environmental Investments* included in the 2007 Annual Reports for further information.

- CERCLA, which imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2007 Annual Reports, under the heading entitled *The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation* for further information.

- The Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2007 Annual Reports, under the heading entitled *Environmental Matters - Clean Water Act Regulations* for additional information.

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

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters*, included in the 2007 Annual Reports, for further information with respect to environmental issues.

While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices (in Ohio and Texas), without such recovery those costs could adversely affect future results of operations and cash flows, and possibly financial condition. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. In October 2007, we settled the New Source Review litigation with the EPA, the United States Department of Justice, various states and special interest groups. The litigation challenged whether modifications to or maintenance of certain coal-fired generating plants required additional permitting or pollution control technology. In settling, we agreed to invest in additional environmental controls for our plants before 2019. We also paid a $15 million civil penalty and will provide $36 million for environmental projects coordinated with the federal government and $24 million to the states for environmental mitigation. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2007 Annual Reports, for more information regarding the settled litigation and other environmental matters.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2005, 2006 and 2007 and the current estimates for 2008, 2009 and 2010 are shown below, in each case excluding AFUDC or capitalized interest. AEP expects to make substantial investments in addition to the amounts set forth below in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards which have been adopted and have deadlines for compliance after 2010 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 6 to the consolidated financial statements, entitled *Commitments, Guarantees and Contingencies*, included in the 2007 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2005 Actual	2006 Actual	2007 Actual	2008 Estimate	2009 Estimate	2010 Estimate
			(in thousands)			
Total AEP System*	$811,400	$1,366,200	$994,100	$875,300	$606,400	$394,200
APCo	231,200	532,800	351,900	315,900	255,900	177,100
CSPCo	32,200	138,900	130,000	139,900	66,800	23,700
I&M	62,900	23,200	9,300	51,500	20,500	3,100
OPCo	458,600	660,800	481,700	291,700	179,200	43,100
PSO	200	500	1,500	25,800	22,100	47,000
SWEPCo	11,900	21,000	14,300	33,000	32,700	66,800

* Includes expenditures of both the subsidiaries shown below and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances. A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

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

UTILITY OPERATIONS

GENERAL

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

ELECTRIC GENERATION

Facilities

AEP's public utility subsidiaries own or lease approximately 37,000 MW of domestic generation. See *Item 2 — Properties* for more information regarding AEP's generation capacity.

AEP Power Pool and CSW Operating Agreement

APCo, CSPCo, I&M, KPCo and OPCo are parties to 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." The Interconnection Agreement has been approved by the FERC. The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all AEP East companies. As of December 31, 2007, the member-load-ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	8,132	33.1
CSPCo	4,713	19.2
I&M	4,528	18.5
KPCo	1,665	6.8
OPCo	5,491	22.4

Ohio's electric restructuring law, the Ohio Act, was enacted in 2001. To comply with that law CSPCo and OPCo functionally separated their generation business from their remaining operations. They plan to remain functionally separated through at least December 31, 2008 as authorized by their rate stabilization plans approved by the PUCO. As permitted by the Ohio Act, CSPCo and OPCo can implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about proposed legislation to address the period following the expiration of the rate stabilization plans. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2007 Annual Reports, for more information.

Since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which provides, among other things, for the transfer of emission allowances associated with transactions under the Interconnection Agreement. The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement during the years ended December 31, 2005, 2006 and 2007:

	2005	2006	2007
		(in thousands)	
APCo	$288,000	$319,500	$454,800
CSPCo	285,600	281,700	173,000
I&M	(197,400)	(146,100)	(93,200)
KPCo	42,200	38,800	41,200
OPCo	(418,400)	(493,900)	(575,800)

PSO, SWEPCo 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 these public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other public utility subsidiary parties as capacity commitments. Parties are compensated for energy delivered to the 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 in their region are generally shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties. The separation of the generation business undertaken by TCC and TNC to comply with the Texas Act has made their business operations incompatible with the CSW Operating Agreement. As a result, with FERC approval, these companies are no longer parties to, and no longer supply generating capacity under, the CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2005, 2006 and 2007:

	2005	2006	2007
		(in thousands)	
PSO	$27,600	$(15,300)	$(17,500)
SWEPCo	(27,500)	9,900	16,800
TCC	0	0	0
TNC	(100)	5,400	700

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as Ohio considers continuing to transition to the use of market rates for generation and as Virginia completes it final year of transition before returning to a form of cost-based regulation. See *Regulation — Rates* under *Item 1, Utility Operations*.

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

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies, PSO and SWEPCO. 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 for activities within each zone. Because TCC and TNC have exited the generation business, these two companies are no longer parties to the System Integration Agreement.

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2007, counterparties and exchanges have posted approximately $43 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $77 million with counterparties and exchanges). Since open trading contracts are valued based on market power prices, exposures change daily.

Fuel Supply

The following table shows the sources of fuel used by the AEP System:

	2005	2006	2007
Coal and Lignite	83%	85%	85%
Natural Gas	6%	6%	6%
Nuclear	10%	9%	9%
Hydroelectric and other	1%	<1%	<1%

Variations in the generation of nuclear power are primarily related to refueling and maintenance outages. Price increases in one or more fuel sources relative to other fuels generally result in increased use of other fuels.

Coal and Lignite: AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. The price for most solid fuels generally has been increasing. Management has responded to increases in the price of coal by rebalancing the coal used in its generating facilities with coal from different coal regions and sources that have different heat and sulfur contents. This rebalancing is an ongoing process that is expected to continue, significantly enabled by the installation of scrubbers at a number of our generating facilities. Management believes that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns, leases or controls more than 8,400 railcars, 692 barges, 16 towboats and a coal handling terminal with 20 million tons of annual capacity to move and store coal for use in its generating facilities. See MEMCO Operations for a discussion of AEP's for-profit coal and other dry-bulk commodity transportation operations that are not part of AEP's Utility Operations segment.

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

	2005	2006	2007
Total coal delivered to AEP System plants (thousands of tons)	72,321	76,045	72,644
Average price per ton of purchased coal	$32.84	$35.27	$36.65

The coal supplies at AEP System plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, labor issues and weather conditions which may interrupt production or deliveries. At December 31, 2007, the System's coal inventory was approximately 29 - 33 days of normal usage. This estimate assumes that the total supply would be utilized through the operation of plants that use coal most efficiently.

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

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

Natural Gas: Through its public utility subsidiaries, AEP consumed over 108 billion cubic feet of natural gas during 2007 for generating power. A portfolio of long-term, monthly, seasonal firm and daily peaking purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant.

Nuclear: I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets. I&M also leases nuclear fuel.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M anticipates that the Cook Plant has sufficient storage capacity for its spent nuclear fuel to permit normal operations through 2013. I&M has entered into an agreement to provide for onsite dry cask storage.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the spent nuclear fuel disposal program. In 2006, when the most recent study was done, the estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranged from $733 million to $1.3 billion in 2006 non-discounted dollars. At December 31, 2007, the total decommissioning trust fund balance for the Cook Plant was $1.057 billion. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected;
- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy);
- Further development of regulatory requirements governing decommissioning;
- Technology available at the time of decommissioning differing significantly from that assumed in studies;
- Availability of nuclear waste disposal facilities; and
- Availability of a DOE facility for permanent storage of spent nuclear fuel.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. We will seek recovery from customers through our regulated rates if actual decommissioning costs exceed our projections. See Note 10 to the consolidated financial statements, entitled *Nuclear*, included in the 2007 Annual Reports, for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste: The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available, but South Carolina and Utah license low-level radioactive waste disposal sites which currently accept low-level radioactive waste from Michigan. I&M's access to the Barnwell, South Carolina facility is currently allowed through the end of fiscal year 2008. With some modifications to existing facilities, I&M will have capacity for onsite storage of that waste currently shipped to Barnwell, South Carolina for the duration of its licensed operation of Cook Plant. There is currently no set date limiting I&M's access to the Utah facility; however this facility does not accept all classifications of low level waste.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC and called the Mone Plant. OPCo is entitled to 100% of the power generated by the Mone Plant, and is responsible for the fuel and other costs of the facility through May 2012, as extended. Following that, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the Mone Plant, and both parties will generally be responsible for their allocable portion of the fuel and other costs of the facility.

Certain Power Agreements

I&M: The Unit Power Agreement between AEGCo and I&M, dated March 31, 1982, provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

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

CSPCo: The Unit Power Agreement between AEGCo and CSPCo, dated March 15, 2007, provides for the sale by AEGCo to CSPCo of all the capacity and associated unit contingent energy and ancillary services available to AEGCo at the Lawrenceburg Plant that are scheduled and dispatched by CSPCo. CSPCo is obligated to pay a capacity charge (whether or not power is available from the Lawrenceburg Plant), the fuel, operating and maintenance charges associated with the energy dispatched by CSPCo, and to reimburse AEGCo for other costs associated with the operation and ownership of the Lawrenceburg Plant. The agreement will continue in effect until December 31, 2017 unless extended as set forth in the agreement.

OVEC: AEP and several unaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Until September 1, 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are now entitled to receive and obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Amended and Restated Inter-Company Power Agreement, which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms on March 12, 2026. AEP and the other owners have been evaluating the need for environmental investments related to their ownership interests, which are material. In December 2006, OVEC's Board of Directors authorized interim capital expenditures totaling $366 million in order to complete detailed engineering and began construction of flue gas desulfurization (sulfur dioxide scrubber) projects and the associated scrubber waste disposal landfills. In November 2007, OVEC's Board of Directors authorized additional interim capital expenditures of up to $82.8 million for completion of the associated scrubber waste disposal landfills. If approved, the estimated total cost to complete the scrubber and landfill projects would be in excess of $1 billion, which OVEC would expect to finance through issuing debt.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

AEP's public utility subsidiaries (other than AEGCo) own and operate transmission and distribution lines and other facilities to deliver electric power. See *Item 2—Properties* for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's public utility subsidiaries in their service territories. These sales are made at rates established and approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See *Regulation—Rates*. The FERC regulates and approves the rates for wholesale transmission transactions. See *Item 1 –Utility Operations - Regulation—FERC*. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's public utility subsidiaries (other than AEGCo) hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see *Item 1 –Utility Operations - Competition*.

AEP Transmission Pool

Transmission Equalization Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system and are parties to the TEA, defining how they share the costs and benefits associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345kV and above) and certain facilities operated at lower voltages (138kV up to 345kV). The TEA has been approved by the FERC. Sharing under the TEA is based upon each company's "member-load-ratio." The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. The respective peak demands and member-load-ratios as of December 31, 2007 are set forth above in the section titled *ELECTRIC GENERATION* – AEP Power Pool and CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties to the TEA during the years ended December 31, 2005, 2006 and 2007:

	2005	2006	2007
		(in thousands)	
APCo	$8,900	$(16,000)	$(25,000)
CSPCo	34,600	46,000	51,900
I&M	(47,000)	(37,000)	(34,600)
KPCo	(3,500)	(2,000)	(800)
OPCo	7,000	9,000	8,500

Transmission Coordination Agreement: PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, which has been approved by the FERC. Under the TCA, a coordinating committee is charged with the responsibility of (i) overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, (ii) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (iii) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff. Pursuant to the TCA, the AEP West companies have delegated to AEPSC responsibility for monitoring the reliability of their transmission systems and administering the AEP OATT on their behalf. Prior to September 2005, the TCA also provided for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the AEP OATT. Since then, these allocations have been determined by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

The following table shows the net (credits) or charges allocated among the parties to the TCA prior to September 2005, and pursuant to the SPP OATT and ERCOT protocols as described above during the years ended December 31, 2005, 2006 and 2007:

	2005	2006	2007
		(in thousands)	
PSO	$3,500	$1,800	500
SWEPCo	5,200	(1,900)	(500)
TCC	(3,800)	1,100	1,100
TNC	(4,900)	(1,000)	(1,100)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See *Item 1 – Utility Operations - Regional Transmission Organizations*, below. Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission: AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East and AEP West companies. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TEA and the TCA. The System Transmission Integration Agreement contains two service schedules that govern:

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

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

Regional Transmission Organizations

The AEP East Companies are members of PJM (a FERC-approved RTO). SWEPCo and PSO are members of the SPP (another FERC-approved RTO). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. The remaining AEP West companies (TCC and TNC) are members of ERCOT. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2007 Annual Reports under the heading entitled *RTO Formation/Integration Costs* and *Transmission Rate Proceedings at the FERC* for a discussion of public utility subsidiary participation in RTOs.

REGULATION

General

Except for transmission and/or retail generation sales in certain of its jurisdictions, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional regulation by the state utility commissions. See *Item 1 – Utility Operations - Electric Restructuring and Customer Choice Legislation* and *Rates*, below. AEP's subsidiaries are also subject to regulation by the FERC under the FPA. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC. EPACT contains key provisions affecting the electric power industry such as giving the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases.

Rates

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

In many jurisdictions, the rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In the ERCOT area of Texas, our utilities have exited the generation business and they currently charge unbundled cost-based rates for transmission and distribution service. In Ohio, rates for electric service are unbundled for generation, transmission and distribution service. Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes. While the historical framework remains in a portion of AEP's service territory, recovery of increased fuel costs through a fuel adjustment clause is no longer provided for in Ohio.

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

Indiana: I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. In January 2008, I&M filed for an increase in its Indiana base rates of $82 million based on a return on equity of 11.5% and a September 30, 2007 test year. The base rate increase includes a $69 million reduction in depreciation. The filing requests trackers for certain variable components of the cost of service including additional PJM costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and net environmental compliance costs. The trackers would increase annual revenues by $46 million. I&M proposes to share 50% of an estimated $96 million of off-system sales margins with ratepayers with a guaranteed minimum of $20 million. A decision is expected from the IURC in early 2009.

Ohio: CSPCo and OPCo each operated as a functionally separated utility and provided "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act through December 31, 2007. The PUCO approved the rate stabilization plans filed by CSPCo and OPCo (which, among other things, address default retail generation service rates from January 1, 2006 through December 31, 2008). Retail generation rates are determined consistent with the rate stabilization plan until December 31, 2008. CSPCo and OPCo are providing and will continue to provide distribution services to retail customers at rates approved by the PUCO. These rates are frozen from their levels as of December 31, 2005 through December 31, 2008. Transmission services will continue to be provided at rates based on rates established by the FERC. CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about pending legislation to address the period following the expiration of the rate stabilization plans. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2007 Annual Reports, for more information.

Oklahoma: PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers in the year following when new annual factors are established. In November 2006, PSO filed a request with the OCC seeking an increase in base rates and other rate relief and the OCC issued a final order in October 2007. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2007 Annual Reports, for additional information.

Texas: TCC has sold all of its generation assets. TNC has one active generation unit, however, all of the output from that unit is sold to a non-utility affiliate pursuant to a 20-year agreement. Most retail customers in TCC's and TNC's ERCOT service area of Texas are served through non-affiliated Retail Electric Providers ("REPs"). TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. In November 2006, TCC and TNC filed requests with the PUCT seeking increases in the rates charged to REPs for delivering electricity over their transmission and distribution lines. The PUCT granted increases during 2007. See Note 4 to the consolidated financial statements, entitled *Rate Matters* included in the 2007 Annual Reports, for additional information. In August 2006, the PUCT delayed competition in the SPP area of Texas until at least January 1, 2011. As such, the PUCT continues to approve base and fuel rates for SWEPCo's Texas operations.

Virginia: APCo currently provides retail electric service in Virginia at unbundled rates. In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation and supply rates after the December 31, 2008 expiration of capped rates. The law provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of a variety of costs and a minimum allowed return on equity which will be based on the average earned return on equity of regional vertically integrated electric utilities. The law also provides that utilities may retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual.

In May 2007, the VSCC approved an overall annual increase in base rates. In December 2007, the VSCC approved recovery of certain recurring environmental and reliability costs (the first of several anticipated requests for costs expected to be incurred). In February 2008, the VSCC approved an adjustment in APCO's fuel factor and the submission of PJM-related costs in fuel factor review and recovery, and authorized APCo to retain a share of margins from its off-system sales. For a more complete discussion of these matters, see Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2007 Annual Reports.

West Virginia: APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC. West Virginia generally allows for timely recovery of fuel costs. In June 2007, the WVPSC approved a settlement agreement that provided for recovery of additional costs effective July 1, 2007. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2007 Annual Reports, for additional information on current rate proceedings.

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

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

Jurisdiction	Status of Base Rates for Power Supply	Status of Base Rates for Energy Delivery	Fuel Clause Rates (4) Status	Fuel Clause Rates (4) Off-System Sales Profits Shared with Ratepayers	Percentage of AEP System Retail Revenues (1)
Ohio	See footnote 2	Distribution frozen through 2008 (2)	None	Not applicable	33%
Oklahoma	Not capped or frozen	Not capped or frozen	Active	Yes	13%
Texas ERCOT	Not applicable (3)	Not capped or frozen	Not applicable	Not applicable	8%
Texas SPP	Not capped or frozen (3)	Not capped or frozen	Active	Yes	5%
Indiana	Not capped or frozen	Not capped or frozen	Active	No	9%
Virginia	Capped until 12/31/08	Capped until 12/31/08	Active	Yes	9%
West Virginia	Not capped or frozen	Not capped or frozen	Active	Yes	10%
Louisiana	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%
Kentucky	Not capped or frozen	Not capped or frozen	Active	Yes, above and below base levels	4%
Arkansas	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	2%
Michigan	Not capped or frozen	Not capped or frozen	Active	Yes, in some areas	2%
Tennessee	Not capped or frozen	Not capped or frozen	Active	No	1%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2007.

(2) The PUCO has approved the rate stabilization plan filed by CSPCo and OPCo that began after the market development period and extends through December 31, 2008 during which OPCo's retail generation rates will increase 7% annually and CSPCo's retail generation rates will increase 3% annually. Distribution rates are frozen, with certain exceptions, through December 31, 2008. See Note 4 to the consolidated financial statements, entitled *Rate Matters*.

(3) TCC and TNC are no longer in the retail generation supply business. TCC and TNC provide only regulated delivery services in ERCOT. SWEPCO is a vertically integrated utility that provides retail electric service in the SPP area of Texas.

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

FERC

Under the FPA, the FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its control area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct that prohibit utilities' system operators from providing non-public transmission information to the utility's merchant energy employees. Utilities are permitted to seek recovery of certain prudently incurred stranded costs that result from unbundled transmission services.

The FERC oversees the voluntary formation of RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. As a condition of the FERC's approval in 2000 of AEP's merger with CSW, AEP was required to transfer functional control of its transmission facilities to one or more RTOs. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

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 the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight.

ELECTRIC RESTRUCTURING AND CUSTOMER CHOICE LEGISLATION

Certain states in AEP's service area have adopted restructuring or customer choice legislation. In general, this legislation provides for a transition from bundled cost-based rate regulated electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier. At a minimum, this legislation allows retail customers to select alternative generation suppliers. Electric restructuring and/or customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan and the ERCOT area of Texas. Electric restructuring in the SPP area of Texas has been delayed by the PUCT until at least 2011. AEP's public utility subsidiaries operate in both the ERCOT and SPP areas of Texas. Customer Choice also began in Virginia on January 1, 2002, but will end beginning in 2009 pursuant to the passage of legislation providing for the re-regulation of electric utilities' generation and supply rates.

Ohio Restructuring

Currently, the Ohio Act requires vertically integrated electric utility companies that are in the business of providing competitive retail electric service in Ohio to separate their generating functions from their transmission and distribution functions. Following the market development period (which ended December 31, 2005), retail customers receive distribution and, where applicable, transmission service from the incumbent utility whose distribution rates are approved by the PUCO and whose transmission rates are based on rates established by the FERC. The PUCO approved CSPCo's and OPCo's RSPs that, among other things, addressed default generation service rates from January 1, 2006 through December 31, 2008. See *Item 1 – Utility Operations - Regulation—FERC* for a discussion of FERC regulation of transmission rates, *Regulation—Rates—Ohio* and Note 4 to the consolidated financial statements entitled *Rate Matters*, included in the 2007 Annual Reports, for a discussion of the impact of restructuring on distribution rates. The PUCO authorized CSPCo and OPCo to remain functionally separated through 2008.

The Ohio Act requires CSPCo and OPCo to begin implementing market-based rates on January 1, 2009, following the expiration of their RSPs. However, in August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. The legislation has been passed by the Ohio Senate and is being considered by the Ohio House of Representatives. AEP management is working closely with various stakeholders to achieve a principled, fair and well-considered approach to electric supply pricing.

Texas Restructuring

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

- gave Texas customers the opportunity to choose their REP beginning January 1, 2002 (delayed until at least 2011 in the SPP portion of Texas),
- required each utility to legally separate into a REP, a power generation company and a transmission and distribution utility, and
- required that REPs provide electricity at generally unregulated rates, except that until January 1, 2007 the prices that could be charged to residential and small commercial customers by REPs affiliated with a utility within the affiliated utility's service area were set by the PUCT, until certain conditions in the Texas Act were met.

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

In May 2005, TCC filed its stranded cost quantification application, or true-up proceeding, with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. Other parties have appealed the PUCT's final order as unwarranted or too large; TCC has appealed seeking additional recovery consistent with the Texas Act and related rules. TCC intends to appeal any final adverse rulings regarding the PUCT's order in the true-up proceedings.

After PUCT approval, in October 2006 TCC issued $1.74 billion of securitization bonds, including additional issuance and carrying costs through the date of issuance. The PUCT authorized negative competition transition charges in the amount of $356 million in October 2006. TCC is required to refund this amount to its ratepayers. For a discussion of (i) regulatory assets and stranded costs subject to recovery by TCC and (ii) rate adjustments made after implementation of restructuring to allow recovery of certain costs by or with respect to TCC and TNC, see Note 4 to the consolidated financial statements entitled *Rate Matters* included in the 2007 Annual Reports.

Michigan Customer Choice

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Rates for retail electric service for I&M's Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2007, none of I&M's Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Virginia Re-regulation

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation and supply rates after the December 31, 2008 expiration of capped rates. The law provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of a variety of costs and a minimum allowed return on equity which will be based on the average earned return on equity of regional vertically integrated electric utilities. The law also provides that utilities may retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual.

COMPETITION

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

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

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

SEASONALITY

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

MEMCO OPERATIONS

Our MEMCO Operations Segment transports coal and dry bulk commodities primarily on the Ohio, Illinois, and lower Mississippi rivers. Almost all of our customers are nonaffiliated third parties who obtain the transport of coal and dry bulk commodities for various uses. We charge these customers market rates for the purpose of making a profit. Depending on market conditions and other factors, including barge availability, we have also served AEP utility subsidiary affiliates. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generating plants. We charged affiliated customers rates that reflected our costs. The MEMCO operations include approximately 1,992 barges, 38 towboats and 14 harbor boats that we own or lease.

Competition within the barging industry for major commodity contracts is intense, with a number of companies offering transportation services in the waterways we serve. We compete with other carriers primarily on the basis of commodity shipping rates, but also with respect to customer service, available routes, value-added services (including scheduling convenience and flexibility), information timeliness and equipment. The industry continues to experience consolidation. The resulting companies increasingly offer the widespread geographic reach necessary to support major national customers. Demand for barging services can be seasonal, particularly with respect to the movement of harvested agricultural commodities (beginning in the late summer and extending through the fall). Cold winter weather may also limit our operations when certain of the waterways we serve are closed.

Our transportation operations are subject to regulation by the U.S. Coast Guard, federal laws, state laws and certain international conventions. Legislation has been proposed that could make our towboats subject to inspection by the U.S. Coast Guard.

GENERATION AND MARKETING

Our Generation and Marketing Segment consists of non-utility generating assets and a competitive power supply and energy trading business. We enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in the ERCOT market. The assets utilized in this segment include approximately 310 MW of domestic wind power facilities and 377 MW of coal-fired capacity obtained from TNC's interest in the Oklaunion power station. TNC has entered into a 20-year power agreement transferring this generating capacity to a non-utility affiliate that we operate in order to comply with the separation requirements of the Texas Act. The power obtained from the Oklaunion power station is to be marketed and sold in ERCOT. We are regulated by the PUCT for transactions inside ERCOT and by the FERC for transactions outside of ERCOT. While peak load in ERCOT typically occurs in the summer, we do not necessarily expect seasonal variation in our operations.

OTHER

Gas Operations

In January 2005, we sold a 98% controlling interest in HPL and related assets with the remaining 2% interest being sold to the buyer in November 2005. See Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, and Assets Held for Sale*, included in the 2007 Annual Reports for more information. As a result, management anticipates that our gas marketing operations will be limited to managing our obligations with respect to the gas transactions entered into before these sales.

Plaquemine Cogeneration Facility

Pursuant to an agreement with Dow, AEP constructed an 880 MW cogeneration facility ("Facility") at Dow's chemical facility in Plaquemine, Louisiana that achieved commercial operation status in 2004. Dow used a portion of the energy produced by the Facility and sold the excess power to us. We agreed to sell up to all of the excess 800 MW to Tractebel. Litigation in connection with that power agreement has been settled. For more information, see Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*. In November 2006, we sold our interest in the Facility to Dow. Negotiations for the sale resulted in an after-tax impairment of approximately $136 million. See Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments and Assets Held for Sale.*

For information regarding other non-core investments, see Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments and Assets Held for Sale,* included in the 2007 Annual Reports.

ITEM 1A. RISK FACTORS

General Risks of Our Regulated Operations

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Our planned capital investment program coincides with a material increase in the price of the fuels used to generate electricity. Many of our jurisdictions have fuel clauses that permit us to recover these increased fuel costs through rates without a general rate case. While prudent capital investment and variable fuel costs each generally warrant recovery, in practical terms our regulators could limit the amount or timing of increased costs that we would recover through higher rates. Any such limitation could cause our financial results to be diminished.

While Indiana permits the recovery of prudently incurred costs, our request for rate recovery may not be approved. *(Applies to AEP and I&M.)*

In January 2008, I&M filed a request to increase base rates in its Indiana jurisdiction by approximately $82 million. The request included a return on equity of 11.5% and the ability to introduce additional riders. The requested increase is attributable to additional costs relating to operating in the PJM, reliability enhancement, demand side management, additional off-system sales margin sharing and environmental compliance costs. While regulation in Indiana provides for a return on costs prudently incurred, there can be no assurance that the IURC will approve all of the costs included in our filing or that this process will result in rates providing full recovery in a timely manner. If the IURC denies the requested rate recovery, it could adversely impact future results of operations, cash flows and financial conditions.

The internal allocation of AEP System off-system sales margins has been challenged. *(Applies to APCo, CSPCo, I&M and OPCo.)*

Off-system sales margins are allocated among the AEP System companies pursuant to a FERC-approved agreement among those companies entered into at the time of the merger with CSW. In November 2005, we filed with the FERC a proposed allocation methodology to be used in 2006 and beyond. The original allocations have been challenged in different forums, including a PSO fuel clause recovery proceeding before the OCC. In general, the challenges assert that AEP West companies, acquired in the merger with CSW, are being allocated a disproportionately small amount of the off-system sales margins. The OCC and, separately, a federal district court in Texas have each held that the FERC is the only appropriate adjudicator of such challenges. This holding has been affirmed by a federal appellate court. No proceeding questioning the allocation of our off-system sales is currently before the FERC. If the FERC were to retroactively allocate additional off-system sales margins to the AEP West companies, the AEP East companies may be required to pay money to the AEP West companies. Any such payments could have an adverse effect on the results of operations, cash flows and possibly financial condition of the AEP East companies.

We may not recover costs incurred to construct generating plants that are canceled. *(Applies to each registrant)*

Our business plan for the construction of new generating units involves a number of risks, including construction delays, nonperformance by equipment suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are cancelled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, we may need to impair any construction work-in process assets for any expenses we have incurred.

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

Unless mitigated by timely and adequate regulatory recovery, the cost of repairing damage to our utility facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events, in excess of insurance coverage, when applicable, may adversely impact our revenues, operating and capital expenses and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials.

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

Through I&M, we own the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,143 MW, or 6% of our generation capacity. We are, therefore, subject to the risks of nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the losses of others); and,
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if and when these risks are triggered.

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

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

Our results are likely to be affected by differences in the market and transmission regulatory structures in various regional power markets. The rules governing the various regional power markets, including SPP and PJM, may also change from time to time which could affect our costs or revenues. Because the manner in which RTOs will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

The amount we charged third parties for using our transmission facilities has been reduced and is subject to refund. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. The elimination of the T&O rates reduced the transmission service revenues collected by the RTOs and thereby reduced the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Because intervenors objected to this decision, the SECA fees we collected ($220 million) are subject to refund.

A hearing was held in May 2006 to determine whether any of the SECA revenues should be refunded. In August 2006, the ALJ ruled that the rate design for the recovery of SECA charges was flawed and that a large portion was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory, and that new compliance filings and refunds should be made. The ALJ also found that unpaid SECA rates must be paid in the recommended reduced amount. The FERC has not ruled on the matter. If the FERC upholds the decision of the ALJ, it would disallow $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. We have recorded provisions in the aggregate amount of $37 million related to the potential refund of SECA rates. After completed and in-process settlements, the AEP East companies will have a remaining reserve balance of $35 million to settle the remaining unsettled gross SECA revenues.

An increase in the amount PJM charges us for transmitting power over its network may not be fully recoverable. *(Applies to AEP and I&M.)*

On June 1, 2007, in response to a 2006 FERC order, PJM revised its methodology for calculating the effect of transmission line losses in generation dispatch when determining locational marginal prices. The new method is designed to recognize the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Due to the implementation of the new methodology, we experienced an increase in the cost of transmitting energy to customer load zones in the PJM. AEP has initiated discussions with PJM regarding the impact of the new methodology and will pursue a modification through the appropriate stakeholder processes. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates. Recovery has been authorized by the PUCO and VSCC. The filing with the IURC is pending and filings in other affected jurisdictions are planned. In the interim, such costs in these jurisdictions will have an adverse effect on future results of operations and cash flows. Management is unable to predict whether full recovery will ultimately be approved.

We could be subject to higher costs and/or penalties related to mandatory reliability standards. *(Applies to each registrant.)*

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. These standards, which previously were being applied on a voluntary basis, became mandatory in June 2007. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and is guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

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

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, the rates a utility is allowed to charge may or may not match its expenses at any given time. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner.

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

In addition to the multiple levels of state regulation at the states in which we operate, our business is subject to extensive federal regulation. Developments in federal legislative and regulatory initiatives (which have occurred over the past few years and which have generally facilitated competition in the energy sector) and/or (2) state regulation could cause the regulatory environment to become significantly more restrictive. Further alteration of the regulatory landscape in which we operate will impact the effectiveness of our business plan and may, because of the continued uncertainty, harm our financial condition and results of operations.

At times, demand for power could exceed our supply capacity. *(Applies to each registrant.)*

We are currently obligated to supply power in parts of eleven states. From time to time, because of unforeseen circumstances, the demand for power required to meet these obligations could exceed our available generation capacity. If this occurs, we would have to buy power from the market. We may not always have the ability to pass these costs on to our customers. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage were brief, we could suffer substantial losses that could reduce our results of operations.

Risks Related to Market, Economic or Financial Volatility

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

Since the bankruptcy of Enron, the credit ratings agencies have periodically reviewed our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

If Moody's or S&P were to downgrade the long-term rating of any of the securities of the registrants, particularly below investment grade, the borrowing costs of that registrant would increase, which would diminish its financial results. In addition, the registrant's potential pool of investors and funding sources could decrease. In February 2008, Fitch downgraded the senior unsecured debt rating of PSO to BBB+ with stable outlook. Moody's placed the senior unsecured debt rating of APCo, OPCo, SWEPCo and TCC on negative outlook in January 2008. Moody's assigns the following ratings to the senior unsecured debt of these companies: APCo Baa2, OPCo A3, SWEPCo Baa1 and TCC Baa2.

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

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. *(Applies to AEP.)*

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. In addition, any payment of dividends, distributions or advances by the utility subsidiaries to AEP would be subject to regulatory or contractual restrictions.

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

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations in a manner that would not likely be sustainable.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

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

We are heavily exposed to changes in the price and availability of coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are heavily exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. According to our estimates, we have procured sufficient emission allowances to cover our projected needs for the next two years and for much of the projected needs for periods beyond that. At some point, however, we may have to obtain additional allowances and those purchases may not be on as favorable terms as those currently obtained.

We also own natural gas-fired facilities, which increases our exposure to market prices of natural gas. Natural gas prices tend to be more volatile than prices for other fuel sources.

The price trends for coal, natural gas and emission allowances have shown material increases in the recent past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal, emission allowances or natural gas costs, we may be unable to pass on the changes in costs to our customers.

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

In Ohio, we have limited ability to pass on our fuel costs to our customers. *(Applies to AEP, CSPCo and OPCo.)*

Because generation is no longer regulated in Ohio, we are exposed to risk from changes in the market prices of coal, natural gas, and emissions allowances used to generate power. The prices of coal, natural gas and emissions allowances have increased materially in the recent past. The protection afforded by retail fuel clause recovery mechanisms has been eliminated by the implementation of customer choice in Ohio, which represents approximately 20% of our fuel costs. As long as generating costs cannot be passed through to customers as a matter of right in Ohio, we retain these risks. If we cannot recover an amount sufficient to cover our actual fuel costs, our results of operations and cash flows would be adversely affected.

Downgrades in the credit ratings of companies insuring certain of our financings could cause our costs of borrowing to increase for the foreseeable future. *(Applies to each registrant.)*

A significant amount of our financings involve the periodic resetting of the interest rates applicable in those financings pursuant to auctions among investors ("Auction Rate Bonds"). In order to attract additional investors to these auctions, we often procure financial guaranty policies that insure our obligation to pay interest and principal on our Auction Rate Bonds. Credit downgrades and financial difficulties of certain providers of financial guaranty policies have significantly reduced investor willingness to place bids on Auction Rate Bonds. These events have caused the interest rates on Auction Rate Bonds to increase, thereby increasing our cost of capital and diminishing our earnings. While we may seek to limit the impact of these increased costs by attempting to refinance our Auction Rate Bonds, there can be no assurance as to our ability to do so at attractive rates.

Risks Relating to State Restructuring

In Ohio, our future rates are uncertain. *(Applies to AEP, OPCo and CSPCo.)*

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. In August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. The legislation has been passed by the Ohio Senate and still must be considered by the Ohio House of Representatives. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009. A return to cost-based rates for generation supply in Ohio could have an adverse impact on our financial condition, future results of operations and cash flows. Further, the return of cost-based regulation could cause the generation business of CSPCo and OPCo to meet the criteria for application of regulatory accounting principles. Results of operations and financial condition could be adversely affected if and when CSPCo and OPCo are required to re-establish certain net regulatory liabilities applicable to their generation supply business.

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

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

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

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately seventy REPs. In 2007, TCC's largest customer accounted for 23% of its operating revenues; TNC's largest customer (a non-utility affiliate) accounted for 35% of its operating revenues and its second largest customer accounted for 15% of its operating revenues. Adverse economic conditions, structural problems in the Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows and thereby have an adverse effect on our liquidity.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with environmental laws are significant and the cost of compliance with future environmental laws could harm our cash flow and profitability or cause some of our electric generating units to be uneconomical to maintain or operate. *(Applies to each registrant.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. Further, environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from our estimates. All of the costs are incremental to our current investment base and operating cost structure. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices (in Ohio and Texas), without such recovery those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations. *(Applies to each registrant.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. In July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal common law. The trial court dismissed the suits and plaintiffs have appealed the dismissal. While we believe the claims are without merit, the costs associated with reducing CO_2 emissions could harm our business and our results of operations and financial position.

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

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

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

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

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

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

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

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

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

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

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

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions caused by transportation constraints, adverse weather, non-performance by our suppliers and other factors; and
- catastrophic events such as fires, earthquakes, explosions, hurricanes, terrorism, floods or other similar occurrences.

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

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

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

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

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

UTILITY OPERATIONS

At December 31, 2007, the AEP System owned (or leased where indicated) generating plants with net power capabilities (winter rating) shown in the following table:

Company	Stations		Coal MW	Natural Gas MW	Nuclear MW	Lignite MW	Hydro MW	Oil MW	Total MW
AEGCo	2	(a)	1,300	1,146					2,446
APCo	17	(b)(c)	5,093	523			681		6,297
CSPCo	7	(d)	2,345	1,357					3,702
I&M	9	(a)	2,295		2,191		15		4,501
KPCo	1		1,060						1,060
OPCo	8	(b)(c)(e)	8,472				26		8,498
PSO	8	(f)	1,018	3,238				25	4,281
SWEPCo	10	(g)	1,848	2,167		842			4,857
TNC	11	(f) (h)	377	1,014				8	1,399
System Totals	67		23,808	9,445	2,191	842	722	33	37,041
Percentage of System Totals			64.3	25.5	5.9	2.3	1.9	0.1	

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended. In May 2007, AEGCo completed the purchase of the Lawrenceburg Plant, a 1,146 MW gas-fired unit (winter rating) in Indiana from Public Service Electric and Gas Company. In September 2007, AEGCo purchased the Dresden Generating station, a gas-fired unit in Ohio currently under construction. Upon completion, which is expected to be in 2009 or 2010, this unit will be a 580 MW facility.

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

(c) APCo owns Units 1 and 3 and OPCo owns Units 2, 4 and 5 of Philip Sporn Plant, respectively.

(d) CSPCo owns generating units in common with Duke Ohio and DP&L. Its percentage ownership interest is reflected in this table. In April 2007, CSPCo completed the purchase of the Darby Electric Generating station, a 507 MW gas-fired unit (winter rating) in Ohio from DP&L.

(e) The scrubber facilities at the General James M. Gavin Plant are leased. OPCo is permitted to terminate the lease as early as 2010.

(f) As of December 31, 2007, PSO and TNC, along with Oklahoma Municipal Power Authority and The Public Utilities Board of the City of Brownsville, Texas, jointly owned the Oklaunion power station. PSO's ownership interest is reflected in this portion of the table. In February 2007, TCC sold its interest in Oklaunion to The Public Utilities Board of the City of Brownsville, Texas. In order to comply with the separation requirements of the Texas Act, in January 2007, TNC entered into a 20-year purchase power agreement transferring its generating capacity in the Oklaunion power station to a non-utility affiliate.

(g) SWEPCo owns generating units in common with unaffiliated parties. Only its ownership interest is reflected in this table. Also, SWEPCo began commercial operation of Units 3 and 4, of 88 MW each, at its gas-fired Mattison Plant in July 2007. Commercial operation of Units 1 and 2, of 85 MW each, at the Mattison Plant began in December 2007.

(h) TNC's gas-fired and oil-fired generation has been deactivated.

Cook Nuclear Plant

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

	Cook Plant	
	Unit 1	**Unit 2**
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in Kilowatts	1,084,000	1,107,000
Net Capacity Factors (a)		
2007	97.4%	83.8%
2006	80.4%	86.5%
2005	88.8%	97.1%
2004	97.0%	81.6%

(a) Net Capacity Factor values for Unit 1 in 2007 reflect Nominal Net Electrical Rating in Kilowatts of 1,084,000. The Net Capacity Factor values for Unit 1 from 2004 through 2006 reflect the previous Nominal Net Electrical Rating in Kilowatts of 1,036,000. The Net Electrical Rating changed due to low pressure turbine replacement.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. However the ability of I&M to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured. Such costs may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs.

Print

AEP EXPANDS EUROPEAN MARKETING, TRADING CAPABILITIES INTO NORDIC REGION BY HIRING ENRON NORDIC ENERGY STAFF

COLUMBUS, Ohio, Jan. 8, 2002 - AEP Energy Services Ltd., the London-based European wholesale energy marketing and trading subsidiary of American Electric Power (NYSE: AEP), has hired 35 former employees from Enron Nordic Energy and assumed operation of existing offices in Oslo, Norway, and Stockholm, Sweden.

The Nordic energy marketing and trading organization provides AEP Energy Services' European wholesale group with an established capability for power and weather trading, origination and portfolio management in Norway, Sweden, Finland, Denmark and Germany. The team is headed by Thor Lien and is a substantial participant in Nordic markets.

"The Nordic region is a mature energy market, but one where - to date - AEP has not participated," said Hank Jones, senior vice president with AEP Energy Services and head of AEP's wholesale business in Europe. "We've said we would enter the Nordic market only if we acquired or developed the expertise to enable us to be successful in the market.

"Adding Thor and his team immediately provides us with a proven wholesale platform in the Nordic region, extensive market expertise and a capability to utilize the interconnector that moves power between Germany and Denmark," Jones said. "This addition of an established, successful Nordic marketing and trading organization represents another important milestone in our continued growth."

AEP's growth strategy focuses on key aspects of the wholesale fuel and power generation value chain - generation and related energy assets, wholesale marketing and trading of energy commodities, fuel procurement and transportation and related activities. AEP Energy Services continues to aggressively build its wholesale energy capabilities in the United Kingdom and Europe, using AEP's very successful U.S. wholesale structure as a model.

In December, AEP completed the acquisition of Fiddler's Ferry and Ferrybridge, two 2,000 megawatt coal-fired power plants in the United Kingdom, from Edison Mission Energy, a subsidiary of Edison International. The acquisition allows AEP to replicate its successful asset-backed U.S. wholesale model in the UK.

Also in December, AEP Energy Services acquired existing contracts and hired 22 key employees from the Enron international coal team in the UK. The addition of the London-based coal marketing organization provided AEP Energy Services' European wholesale group with an established capability for procurement, transportation and delivery of coal across geographic regions.

American Electric Power is a multinational energy company based in Columbus, Ohio. AEP owns and operates more than 38,000 megawatts of generating capacity, making it America's largest generator of electricity. The company is also a leading wholesale energy marketer and trader, ranking second in North America in wholesale electricity and wholesale natural gas volume. AEP provides retail electricity to more than 7 million customers worldwide and has holdings in the U.S. and select international markets. Wholly owned subsidiaries are involved in power engineering and construction services.

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Print

FERC APPROVES AEP CORPORATE SEPARATION PLAN

COLUMBUS, Ohio, Sept. 27, 2002 - American Electric Power (NYSE: AEP) on Thursday received Federal Energy Regulatory Commission (FERC) approval of its corporate separation plan to form wholly owned regulated and unregulated companies.

AEP filed the request with FERC in July 2001. Securities and Exchange Commission (SEC) approval of the plan is the final approval required. AEP filed documents with the SEC in November 2000 outlining its corporation separation plans.

"We're pleased that the FERC has approved our request and are optimistic that the SEC will do likewise, " said E. Linn Draper Jr., AEP's chairman, president and chief executive officer. "We are encouraged that our corporate separation can be implemented by the end of this year.

"Separation of our regulated and unregulated businesses makes strategic sense for AEP and our shareholders," Draper said. "Our plan will foster accountability within AEP's business units, enable investors to more clearly assess our businesses, permit more efficient financing, and set the stage for possible future options. It also allows us to comply with industry restructuring legislation in Ohio and Texas."

AEP's plan provides for one corporation to hold AEP's subsidiaries whose revenues derive from activities that are competitive and primarily market-based, and for the other corporation to hold AEP's utility subsidiaries that are subject to regulation by at least one state utility commission. Generation-related operations in the deregulated states of Ohio and Texas, and other unregulated operations, would fall under the unregulated corporation while the regulated corporation would house transmission, distribution and regulated generation operations.

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AEP learns of CFTC action

COLUMBUS, Ohio, Oct. 1, 2003 - American Electric Power (NYSE: AEP) has learned that the Commodity Futures Trading Commission (CFTC) has filed a civil action against the company in the United States District Court for the Southern District of Ohio.

AEP has not been served with a copy of the complaint, which was filed late yesterday, but believes that it is based on claims related to the submitting of natural gas trading information to certain trade publications by gas traders no longer employed by AEP.

After learning in September 2002 of false reporting of gas price information at an unrelated company, AEP immediately undertook its own internal investigation of gas price reporting practices. AEP determined that five then-current employees had submitted inaccurate gas trading information to trade publications. The company immediately terminated the five employees, self-reported the incident to the Federal Energy Regulatory Commission (FERC) and the CFTC, publicly announced the employee terminations and put into place procedures to prevent a reoccurrence of the inaccurate submission of gas trading information.

"We have been cooperating with the CFTC in an attempt to seek resolution to this matter," said Jeffrey D. Cross, AEP's general counsel. "While the possibility of civil action always existed, we are surprised the CFTC chose to file at this time. We still believe that a settlement is possible and we are open to that possibility.

"We discovered and self-reported these activities," Cross said. "We have no indication that any current employees were involved in the activities."

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The comments set forth above include forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and 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; abnormal weather conditions; available sources and costs of fuels; availability of generating capacity; the speed and degree to which competition is introduced to our service territories; the ability to recover stranded costs in connection with existing and possible additional deregulation; new legislation and government regulation; oversight and/or investigation of the energy sector or its participants; our ability to successfully control costs; the success of acquiring new business ventures and disposing of existing investments that no longer match our corporate profile; international and country-specific developments affecting foreign investments including the disposition of any current foreign investments and potential additional foreign investments; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; electricity and gas market prices; interest rates; liquidity in the banking, capital and wholesale power markets; actions of rating agencies; changes in technology, including the increased use of distributed generation within our transmission and distribution service territory; and other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events.

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Print

AEP DISMISSES FIVE FOR PROVIDING INACCURATE MARKET DATA FOR INDEXES

COLUMBUS, Ohio, Oct. 9, 2002 - American Electric Power (NYSE: AEP) dismissed five employees involved in natural gas marketing and trading after the company determined that they provided inaccurate price information for use in indexes compiled and published by trade publications.

The company discovered the inaccuracies during an internal review of its trading activities. The market indexes published by trade publications are compiled using trade data voluntarily provided by a variety of industry sources. The company cannot determine if the inaccurate data had any impact on the published indexes.

Prior to learning about the reporting of inaccurate data, AEP had instituted measures to require that all price information provided for use in market indexes be verified and reported by the office of AEP's chief risk officer.

"We did not approve and we do not condone this sort of activity," said Eric van der Walde, executive vice president - AEP Energy Services. "We are serious about ethical business practices and took action immediately after discovering this activity."

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Print

AEP TO REDUCE EXPOSURE TO ENERGY TRADING, DOWNSIZE TRADING AND MARKETING ORGANIZATION

COLUMBUS, Ohio, Oct. 10, 2002 - American Electric Power (NYSE: AEP) said today that it plans to reduce its exposure to speculative energy trading markets and will downsize its trading and wholesale marketing operation.

"We are painfully aware that current market conditions won't reward the scope and scale of our trading and marketing business that we've built over the last several years," E. Linn Draper, AEP's chairman, president and chief executive officer, said during a conference call with financial analysts today. "We are therefore undertaking a significant downsizing of our trading and marketing operation so our future will be limited to risk management around our power and gas assets. That means over the coming weeks we will be reducing our exposure in speculative trading markets and restructuring our commercial organization to support our assets.

"Let me emphasize this decision doesn't reflect a lack of confidence in the competence or integrity of our trading operations," Draper said. "We do expect a reduction in the number of employees in that business, but I anticipate that many will remain with the company."

Eric van der Walde, executive vice president - AEP Energy Services, said the company's wholesale energy efforts would be focused on areas where AEP has assets.

"We will scale back our market activity so that it will be centered around our assets," van der Walde said. "We will be in power markets in the Midwest and Texas, natural gas in the Gulf Coast region and Texas, and the power and coal markets in the United Kingdom."

The company did not provide headcount numbers for the marketing and trading organization.

AEP created AEP Energy Services, its wholesale marketing and trading subsidiary, in 1997 and quickly built it into one of the nation's leading wholesale marketers of power and natural gas. AEP Energy Services also operates approximately 22,000 megawatts of generation in the United States and United Kingdom, 6,400 miles of natural gas pipeline, and 128 billion cubic feet of gas storage.

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Print

ERIC VAN DER WALDE STEPS DOWN AS AEP CHANGES BUSINESS FOCUS; HOLLY KOEPPEL NAMED TO LEAD UNREGULATED BUSINESSES

COLUMBUS, Ohio, Oct. 24, 2002 - Eric van der Walde, executive vice president - wholesale at American Electric Power (NYSE: AEP), today announced his resignation following AEP's decision to limit its energy trading activities to focus on optimizing the value of the company's energy assets.

Holly Koeppel will succeed van der Walde as head of AEP's unregulated businesses, effective immediately. Koeppel, who had been senior vice president - Corporate Development and Strategy, will become executive vice president - Energy Services. Koeppel will report to Tom Shockley, AEP's vice chairman and chief operating officer.

On Oct. 10, E. Linn Draper Jr., AEP's chairman, president and chief executive officer, announced the company's change in strategy. "This decision is motivated by fundamental changes in the energy trading business and is not a reflection on AEP's trading organization," Draper said. "Eric's commercial skills and integrity have served us well in the difficult environment of the last year. We appreciate his contribution."

Van der Walde is expected to remain with AEP in a consulting capacity as the company unwinds its trading operations.

Commenting on the change, van der Walde said, "While I'm disappointed in AEP's change in strategy, I understand and support the decision and will use my best efforts to ensure an orderly transition."

Koeppel, 44, has more than 20 years of experience managing both regulated and unregulated energy assets and businesses. She joined AEP in July 2000 and over the past 12 months has led the successful divestiture of more than $3 billion of non-strategic international assets, SEEBOARD and CitiPower. Prior to joining AEP, Koeppel served for more than 15 years with Consolidated Natural Gas, Pittsburgh. She held a number of positions across the CNG system in the areas of regulatory policy and business development and led the development of key structured transactions in the gas trading business. Her last position with CNG was vice-president of Asia-Pacific operations based in Sydney, Australia.

Koeppel earned bachelor's and master's degrees in business from the Ohio State University. A native of Pittsburgh, she now resides in Upper Arlington, Ohio, with her husband and two children.

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AEP takes steps to strengthen balance sheet: Company to reduce costs, recommend dividend reduction, divest non-core assets

COLUMBUS, Ohio, Jan. 24, 2003 - Citing continued difficult wholesale market conditions that have depressed corporate earnings, American Electric Power (NYSE: AEP) is implementing a plan designed to strengthen the company and improve short-term and long-term performance.

"We are committed to strengthening our balance sheet and have developed a three-part plan for doing so," said E. Linn Draper Jr., AEP's chairman, president, and chief executive officer. "First, we will reduce operations and maintenance costs and capital expenditures, and we have already made substantial progress in that area. Second, we will revise our dividend policy and have discussed that with our board of directors this week. Third, we plan to systematically dispose of non-core assets. In addition, we will continue to evaluate the potential for issuing additional equity.

"The decisions we're making are designed to strengthen the company and improve short-term and long-term performance," Draper said. "The last year has been a tough and turbulent one for AEP and others in our industry because of a series of negative events in the energy sector. The once flourishing wholesale market is no longer the promising business we contemplated three years ago. We will therefore return to the more traditional model of a regulated utility with a small commercial cell that ensures maximum value for the output of our generation assets.

"We are not out of the woods yet, but AEP is still a strong company," Draper said.

Details of the plan include:

- **O&M, capital expenditures** - The continued effort to reduce costs follows AEP's completion of a cost-cutting program that should result in operations and maintenance net savings of more than $200 million when compared to 2002. As part of that program, AEP reduced its workforce by approximately 5 percent, or 1,300 positions, and has made comparable reductions in outside services and other business expenses. In addition, AEP reduced its capital forecast for 2003 to approximately $1.5 billion, a reduction of approximately $200 million from previous levels.
- **Dividend** - During Wednesday's board of directors meeting, the AEP board declared the regular quarterly dividend of $0.60 per share for the first quarter. "Management expects to recommend a 40 percent reduction in the dividend beginning in the second quarter to a quarterly rate of $0.35 per share," Draper said. "This will result in annual cash savings of $340 million and will immediately improve retained earnings as well as create free cash flow that can be used to pay down debt. The decision to reduce the dividend was made after very careful evaluation, since we recognize the importance of the dividend to our shareholders. We believe that we have retained significant value in the dividend we preserved and it still has an attractive yield."
- **Non-core assets** - AEP will conduct an orderly disposition of non-core assets. "This will be accomplished over time and will not be a fire sale," Draper said. "We will take action when we determine that a divestiture brings shareholder value." Proceeds from sales will be used to reduce debt.

"We also recognize the need to evaluate the issuance of equity," Draper said. "While we do not like the dilutive impact on earnings and the additional cash it requires for dividends, incremental equity may be necessary to

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further strengthen our balance sheet and maintain credit quality. We plan to continue active dialogue with the rating agencies on this matter. I believe that, ultimately, a strong BBB credit for the company is in the best interest of all investors."

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News releases and other information about AEP can be found on the World Wide Web at http://www.aep.com.

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AEP addresses factors leading to downgrade by Moody's

COLUMBUS, Ohio, Feb. 10, 2003 - American Electric Power (NYSE:AEP) said today that a decision by Moody's Investors Service to downgrade the debt rating for AEP reflects the weak performance of the company's unregulated investments, but that AEP's core utility businesses remain strong.

Moody's downgraded AEP's senior unsecured rating to Baa3 from Baa2 and lowered its short-term rating for commercial paper to Prime-3 from Prime-2, but said the rating outlook for AEP and its subsidiaries is stable. The rating action concluded Moody's review of AEP.

"We recognize that the weak results from our unregulated investments have been detrimental to overall corporate performance, but we are moving to address that," said Susan Tomasky, AEP executive vice president and chief financial officer. "Our regulated utilities, the core of our business, are strong and stable with reliable earnings and cash flow.

"We have already taken steps that will bring measurable improvements to our balance sheet," Tomasky said. "Last month we announced additional actions to improve performance and ensure continued financial stability during the current difficult times that have hit our industry. We believed that these actions would support the continuation of our Baa2 rating, but Moody's didn't agree. Now we have a stable rating from which to build."

AEP has completed an efficiency program that should result in sustainable net operations and maintenance savings of more than $200 million when compared to 2002. The company will continue to seek ways to further reduce costs. AEP also reduced its capital forecast for 2003 to approximately $1.5 billion, a savings of approximately $200 million from previous levels.

In January, AEP management announced that it expects to recommend the company's board of directors reduce AEP's dividend approximately 40 percent to $0.35 per share beginning in the second quarter. The current dividend is $0.60 per share per quarter. The reduction will result in annual cash savings of approximately $340 million, immediately improve retained earnings and create free cash flow that can be used to pay down debt.

AEP also announced in January that it would divest non-core assets and return to the more traditional model of a regulated utility with a small commercial group that ensures maximum value for the output of the company's generation assets. Funds generated from the sale of non-core assets will be used to reduce debt.

"The sustainable cost reductions we have made will improve our cash flow while we continue to execute the other elements of our plan," Tomasky said. "We're confident we can complete a review and orderly divestiture of non-core assets in a timely fashion while continuing the operation of our strong and stable utility businesses.

"In addition, we will continue to evaluate the potential for issuing additional equity," Tomasky said. "We do not like the dilutive impact on earnings and the additional cash it requires for dividends, but incremental equity may be necessary to further strengthen our balance sheet and maintain credit quality."

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Print

AEP and Snohomish reach settlement in contract dispute

COLUMBUS, Ohio, Feb. 14, 2003 - American Electric Power (NYSE: AEP) and the Public Utility District No. 1 of Snohomish County, Wash. (Snohomish), today announced a settlement in a dispute over a long-term contract signed in January 2001.

According to the terms of the settlement, Snohomish and AEP have agreed to terminate the contract effective today. Snohomish has agreed to pay AEP $59 million. Because the contract was accounted for by AEP on a mark-to-market basis, the negative impact on AEP's 2003 after-tax earnings will be approximately $6.5 million. Snohomish also will withdraw its complaint before the Federal Regulatory Energy Commission (FERC) regarding the contract.

Snohomish and AEP entered into a contract Jan. 25, 2001, in which Snohomish agreed to purchase 25 megawatts of baseload power from AEP for $150 per megawatt-hour for five years beginning Feb. 1, 2001. At the time the agreement was signed, market prices for baseload power in the Northwest were approximately $325 per megawatt-hour for the balance of 2001.

In late December 2001, Snohomish notified AEP that they believed the length of the contract and its terms had become unjust and unreasonable. In June 2002, Snohomish filed a formal complaint with the FERC alleging that the contract violated the Federal Power Act. AEP and Snohomish have been engaged in settlement discussions since January 2002 to address Snohomish's concerns.

"We are gratified to have reached a reasonable resolution to this dispute and avoid a drawn out, expensive proceeding," said Holly Koeppel, AEP's executive vice president - energy services. "The settlement also enables AEP to accelerate cash realization from its portfolio of trading activity in a region where the company does not own assets."

In October 2002, AEP announced that it would reduce its trading activity and focus its market activity in those regions where it owns assets including the Midwest, Texas, the Gulf Coast and the United Kingdom.

American Electric Power owns and operates more than 42,000 megawatts of generating capacity in the United States and select international markets and is the largest electricity generator in the U.S. AEP is also one of the largest electric utilities in the United States, with almost 5 million customers linked to AEP's 11-state electricity transmission and distribution grid. The company is based in Columbus, Ohio.

The comments set forth above include forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, including (1) statements concerning the Company's plans, objectives, expected performance and expenditures and (2) other statements that are other than statements of historical fact. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward-looking statements are electric load and customer growth, abnormal weather conditions, availability of generating capacity, the ability to recover net regulatory assets and other stranded costs in connection with deregulation of generation, the outcome of environmental regulation and litigation, the impact of fluctuation in commodity prices and interest rates, and other risks and unforeseen events over which the Company has no control. The reader is also directed to the Company's periodic filings with the Securities and Exchange Commission for additional factors that may impact the Company's results of operations and financial condition. Furthermore, historical results may not be indicative

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of the Company's future performance.

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Print

AEP is making solid progress to improve performance, Draper tells shareholders at annual meeting

COLUMBUS, Ohio, April 23, 2003 - American Electric Power (NYSE: AEP) has made significant progress toward improving its performance and returning to stable, steady growth, E. Linn Draper Jr., AEP's chairman, president and chief executive officer, told shareholders attending the company's annual meeting today.

"We are acting decisively to put the company back on a steady growth track," Draper said. "We believe we have the right plan to continue our recovery and return to stable growth. Clearly, the task before us now is to continue to execute our plan and thereby continue to restore investor confidence and shareholder value."

AEP has made significant progress in the financing arena during a time when many of its peer companies are having difficulty accessing the financial markets, according to Draper. Already this year, AEP has issued $1.1 billion in equity and $2.5 billion in debt. It also renegotiated and extended a credit facility that was due to mature in May. Additionally, AEP has improved its balance sheet, reducing the percentage of debt from 58.5 to 53.5 percent, well within the 50 to 55 percent range projected by the company for 2003. AEP's liquidity is approximately $4 billion, including about $1.7 billion in cash.

AEP will focus on its core utility operations, which produce stable, predictable earnings and cash flow. "The business of producing, transmitting and delivering electricity continues to be a solid business, despite the soft economy. And it is a business in which we have always excelled," Draper said.

AEP owns and operates the largest generating fleet in the United States, has a large and diverse domestic customer base of nearly 5 million, and electricity rates that are some of the lowest in the nation. According to Draper, the company already has taken actions that will reduce 2003 expenses and provide sustainable net savings of $60 million. AEP management will continue to look for additional ways to reduce operating and maintenance expenses and capital expenditures in its core utility business while maintaining reliable service and a safe working environment.

The company also will continue the orderly scale back of its energy marketing and trading activities, focusing only on those activities that enable it to obtain more value from its core assets. Additionally, the company will divest non-core assets, those outside of the business of producing, transmitting and generating electricity, when market conditions are favorable. AEP has already sold two foreign retail companies in the United Kingdom and Australia, most of its Texas retail operations, a telecommunications subsidiary and other smaller holdings.

"Through these and other initiatives, we will follow through on our commitment to run our business successfully and responsibly. With our talented workforce, our impressive assets and our broad customer base, we have the resources we need to restore value for our investors. And I can assure that we also have the determination," Draper said.

In business items, shareholders re-elected 13 directors to hold office until the next annual meeting or until election of successors. Directors elected to the board are:

- Draper, 61, of Columbus, Ohio
- E.R. Brooks, 65, of Granbury, Texas

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- Donald M. Carlton, 65, of Austin, Texas
- John P. DesBarres, 63, of Park City, Utah
- Robert W. Fri, 67, of Washington, D.C.
- William R. Howell, 67, of Dallas
- Lester A. Hudson Jr., 63, of Greenville, S.C.
- Leonard J. Kujawa, 70, of Atlanta
- Richard L. Sandor, 61, of Chicago
- Thomas V. Shockley III, 57, of Columbus, Ohio
- Donald G. Smith, 67, of Roanoke, Va.
- Linda Gillespie Stuntz, 48, of Washington, D.C.
- Kathryn D. Sullivan, 51, of Columbus, Ohio

In agreement with directors' recommendations, shareholders rejected two shareholder proposals. Approximately 16 percent of shares (or 10 percent of total outstanding shares) were voted in favor of a resolution to adopt a performance-based executive compensation policy linked to an industry peer group stock performance index. Less than 27 percent of shares (or less than 15 percent of total outstanding shares) were voted in favor of a resolution to require AEP to report on the economic risks associated with the company's past, present and future emissions.

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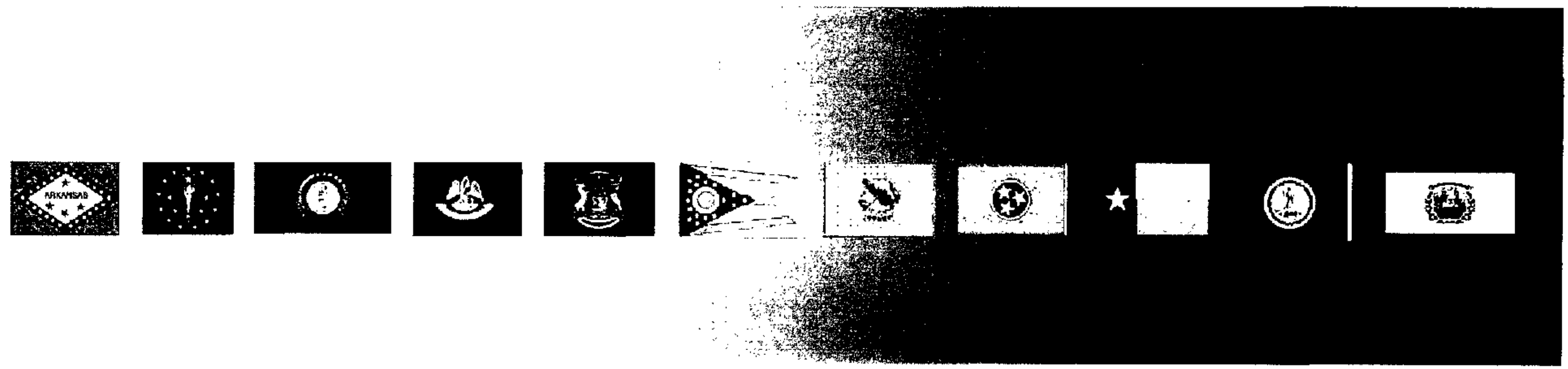

AMERICAN ELECTRIC POWER

Fall EEI Conference

November 11, 2008

AEP AMERICAN ELECTRIC POWER

— STRONG —

— FLEXIBLE —

— ADAPTABLE —

Michael G. Morris

Chairman, President & CEO

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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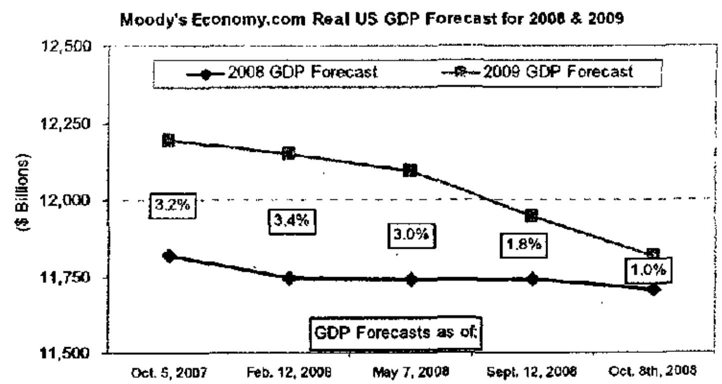
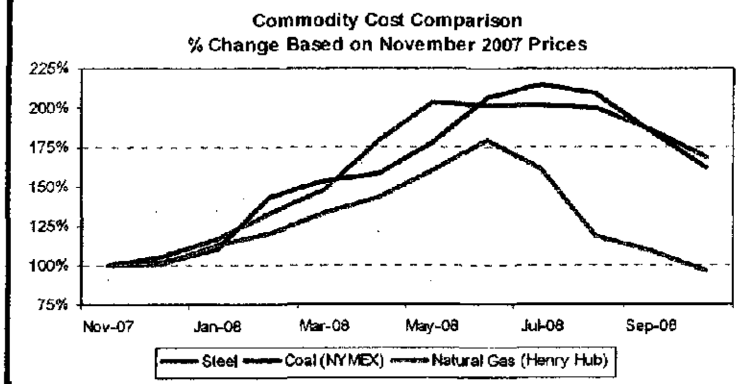
What Has Changed?

Slowed Economic Growth



Volatile Commodity Prices



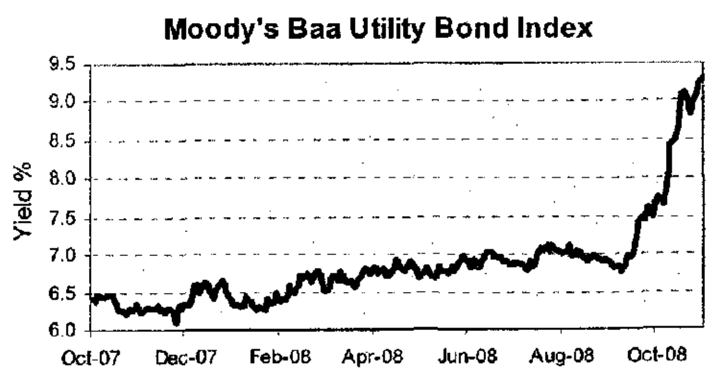
October '08 Prices

Steel: $903 / ton

Coal: $87.48 / ton

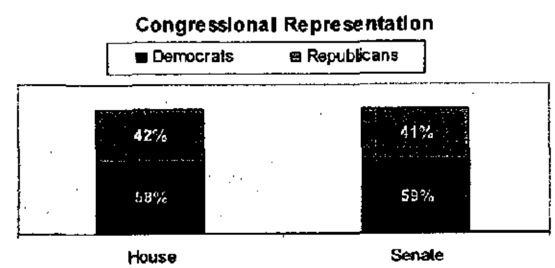
Gas: $6.75 / mmBtu

Crisis in Capital Markets



Election Results

Presidential Election Results:



In nearly every aspect, Fall 2008 has no resemblance of the conditions that surrounded AEP and the entire utility industry in Fall 2007.

Our Strategic Priorities Remain the Same

- "Keep the lights on"
  - Maintain our low-cost and reliable energy production and delivery system
  - Invest to replace aging infrastructure and ensure adequacy of capacity
  - Manage commodity costs
- Environmental priorities
  - Complete our $5.2 billion environmental controls program ($1.0 billion to be spent in 2009-2010)
  - Work to ensure a balanced and logical carbon legislation outcome
- Lead the development of America's high-voltage transmission system
- Collaborate with regulators to more closely match spending with rate recovery

AEP's strategic priorities remain the same, but the steps and timing may be different.

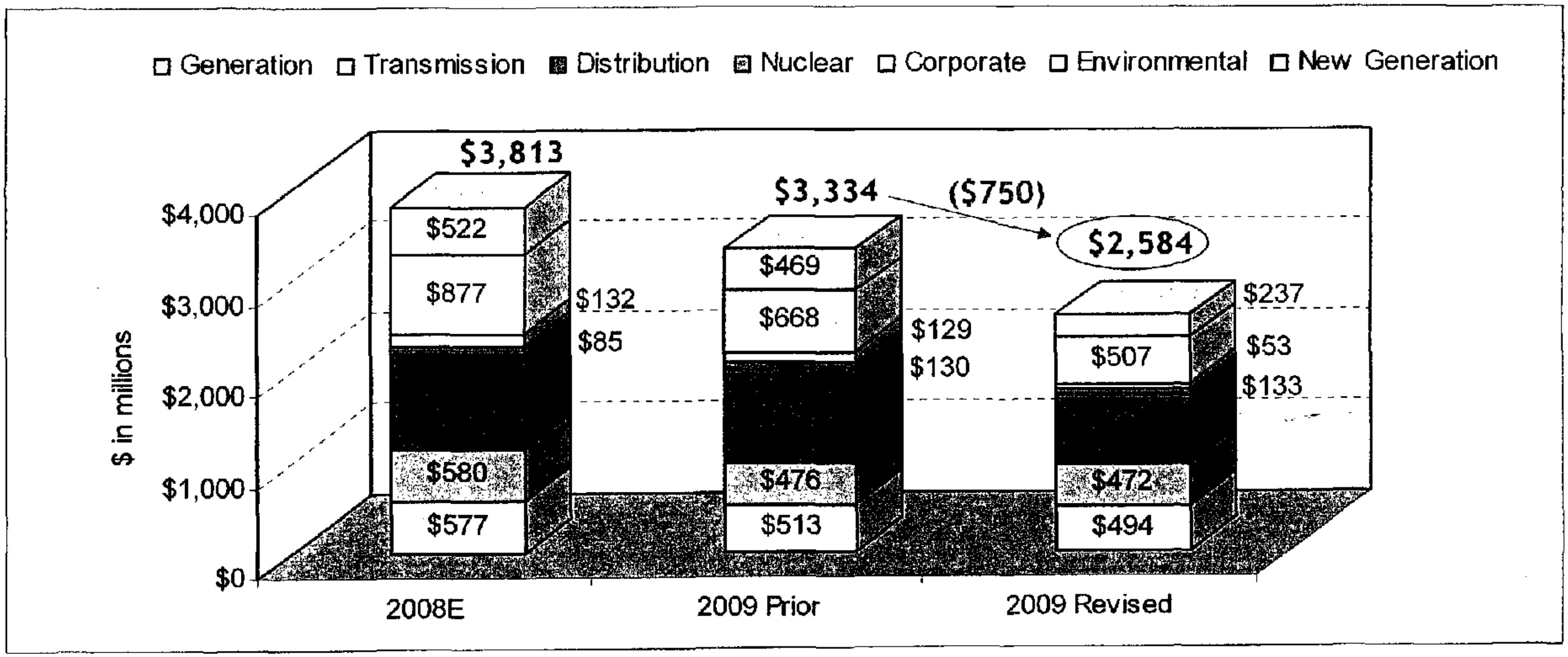
Management Priorities for 2009

- ❑ Secure rate relief in Ohio and other jurisdictions
- ❑ React to the current economic crisis
- ❑ Effectively manage our credit and liquidity
  - Cut capital budget by $750 million to $2.6 billion for 2009
  - Hold 2009 O&M spending flat at 2008 level of $3.3 billion
  - Choose opportunistic points to access capital markets and manage liquidity
- ❑ Maximize flexibility to respond to changing conditions

AEP has a strong reputation and track record for continued performance during difficult economic times.

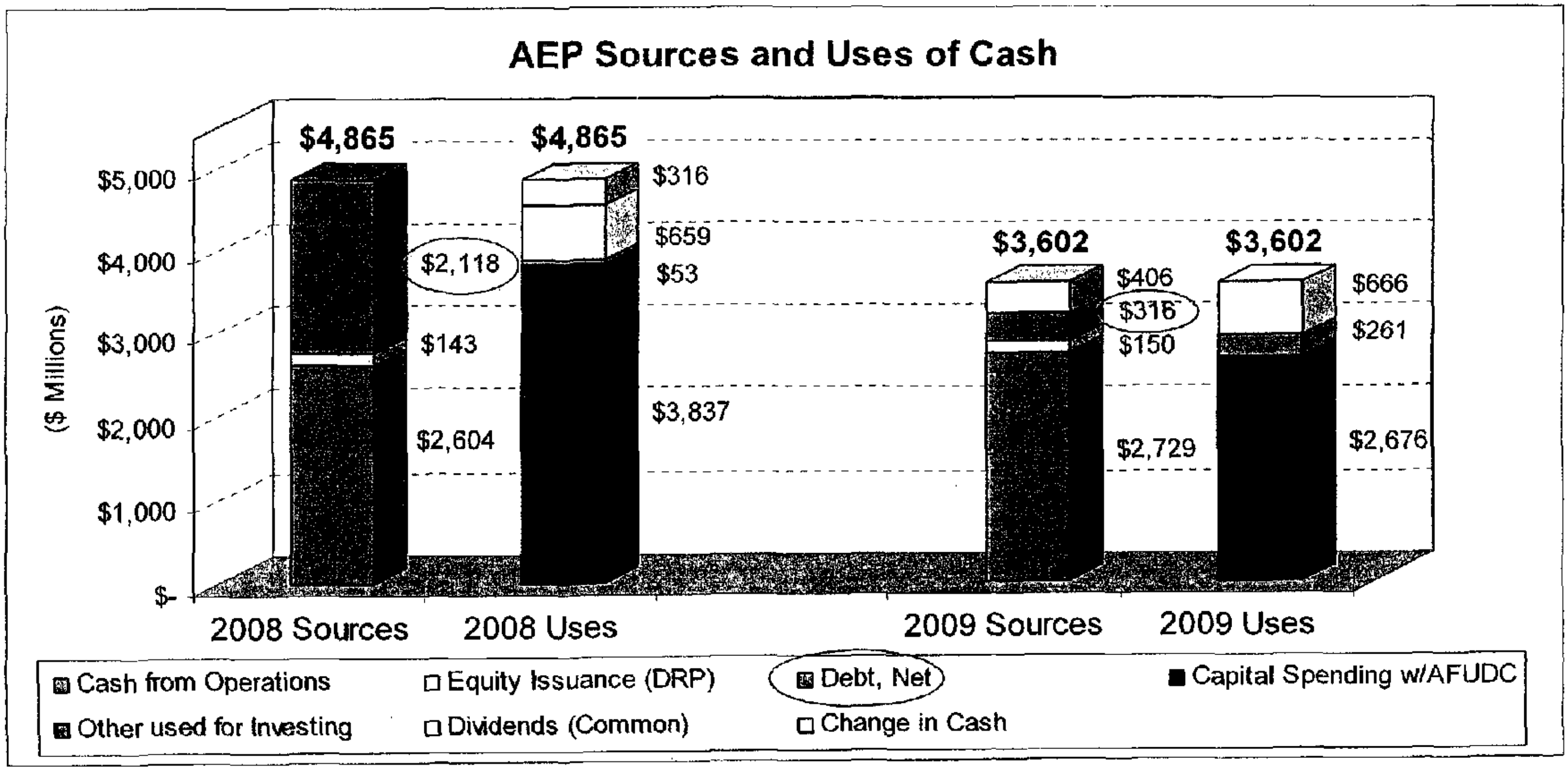
2008 & 2009 Capital Spending

- Capital expenditures for 2009 will be cut by $750 million from previous guidance.



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

2008 & 2009 Ongoing Earnings Guidance

2008E EPS: $3.15 - $3.25

2009E EPS: $3.00 - $3.40

American Electric Power
Earnings Guidance for 2008 and 2009

	2008 Original Guidance		2009 Guidance	
	($ millions)	EPS	($ millions)	EPS
Utility Gross Margin	**8,148**		**8,433**	
Operations & Maintenance	(3,337)		(3,337)	
Interest Exp & Preferred Dividend	(839)		(929)	
All Other Expenses, net	(2,705)		(2,857)	
Utility Operations	**1,267**	**3.15**	**1,310**	**3.23**
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations	77	0.19	75	0.18
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	**1,285**	**3.20**	**1,299**	**3.20**

2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

Continued Earnings Growth

- Outcome for AEP Ohio still an important factor in determining 2009 results and beyond
- Active fuel recovery allowed in each jurisdiction
- Geographic diversity helps to mitigate the effect of the economic slowdown
- Joint venture strategy for transmission investment remains a long-term earnings growth catalyst
- Sustained capital investment in our traditional utility business aligned with regulatory return

Big Sandy Plant

Long-term earnings growth will continue at 4% to 6% per year.

Getting Ready for the Next Cycle

- ❑ Investing in the next generation of energy infrastructure
  - *Approved new generation projects*
  - High-voltage interstate transmission system
  - Advanced distribution infrastructure (gridSMART^{SM})
- ❑ Focused on customer and regulatory relationships
- ❑ Improving financial metrics
- ❑ Committed to dividend policy consistent with past practices
- ❑ Leading the carbon policy debate

AEP is and will continue to be a financially sound, industry leader.

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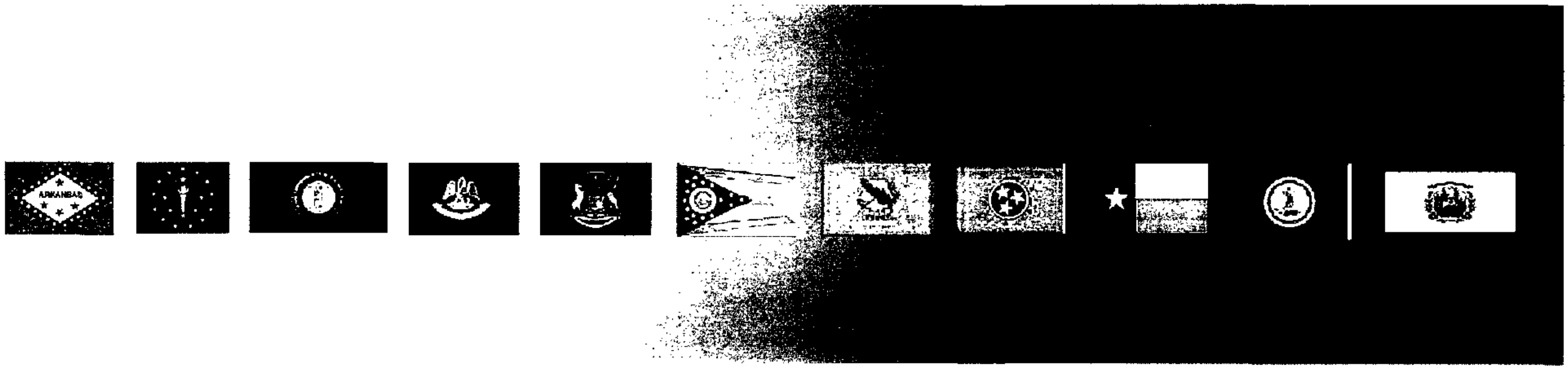

AMERICAN ELECTRIC POWER

Fall EEI Conference

November 9-12, 2008

Handout on Additional Topics

AEP AMERICAN ELECTRIC POWER — STRONG — FLEXIBLE — ADAPTABLE

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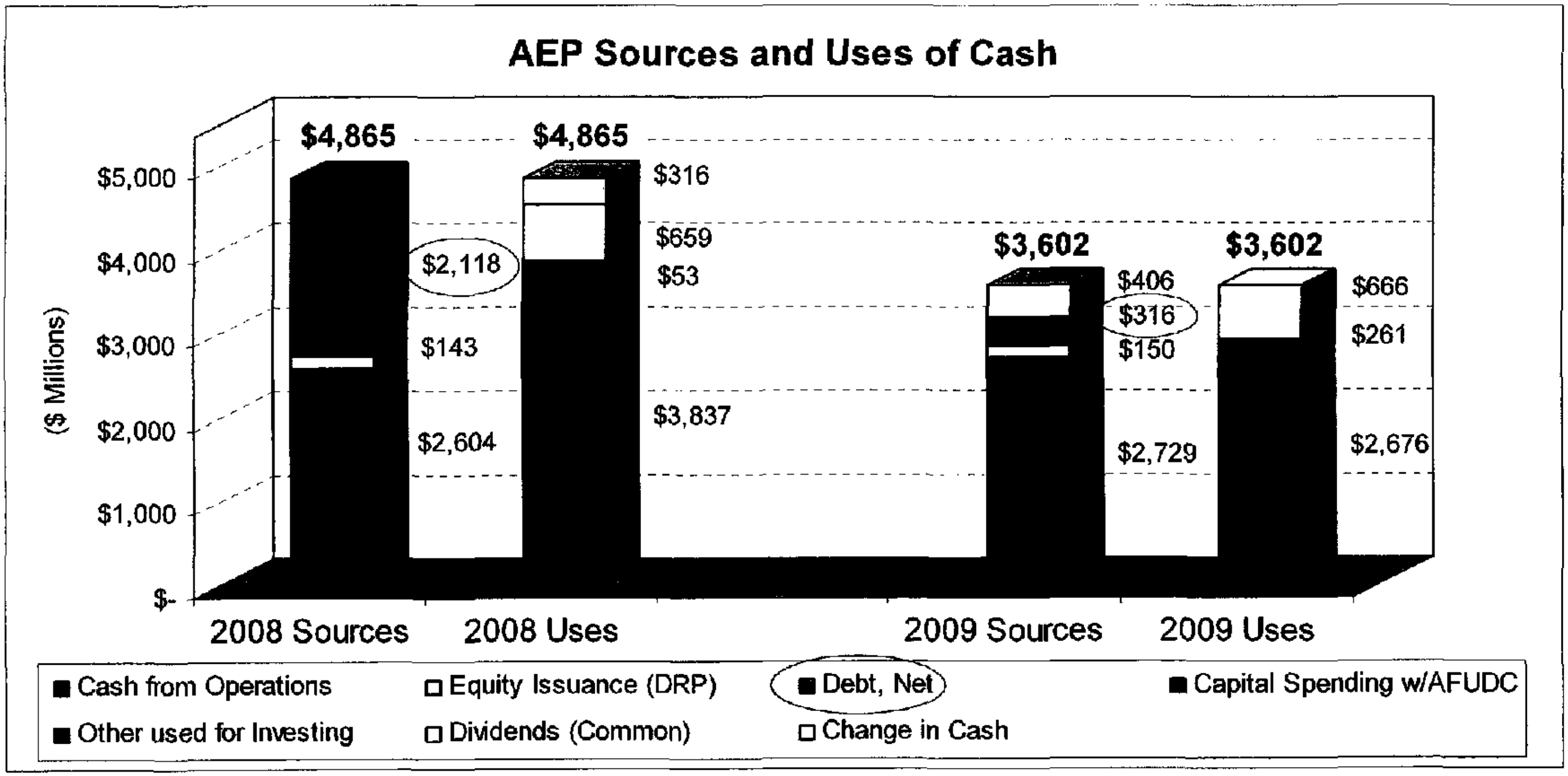
2008 & 2009 Cash Flow Forecast



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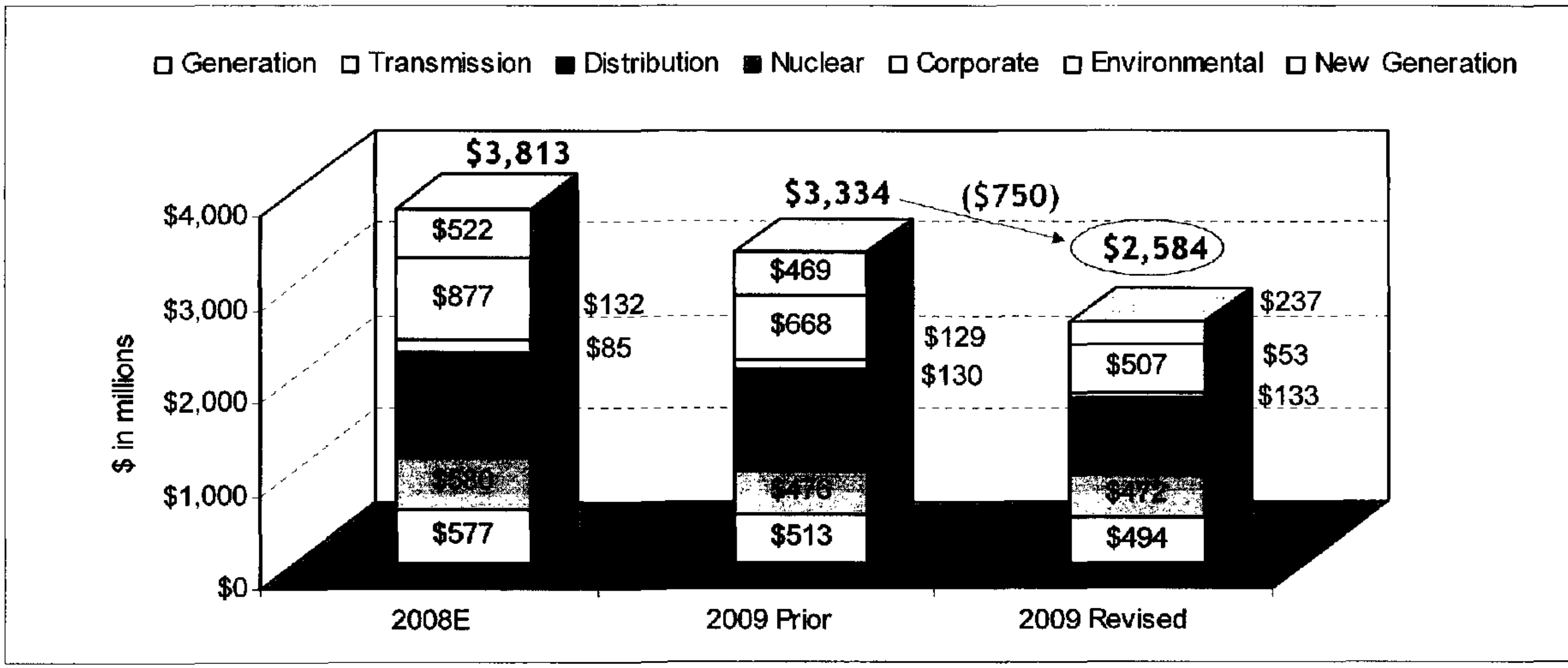

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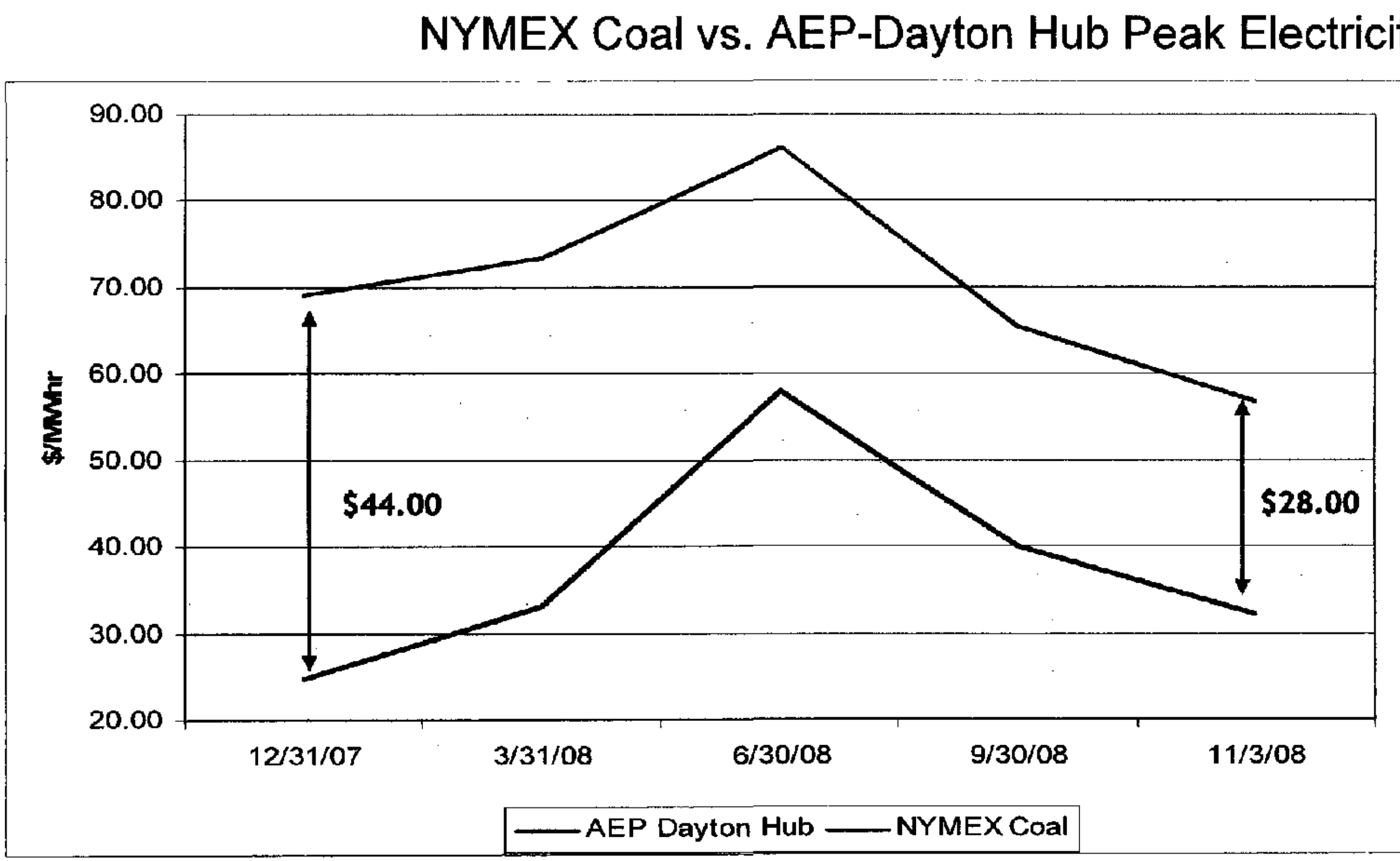
Utility Gross Margin	8,148		8,433	
Operations & Maintenance	(3,337)		(3,337)	
Depreciation & Amortization	(1,451)		(1,546)	
Taxes Other than Income Taxes	(779)		(790)	
Interest Exp & Preferred Dividend	(839)		(929)	
Other Income & Deductions	127		120	
Income Taxes	(602)		(641)	
Utility Operations	1,267	3.15	1,310	3.23
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations:				
AEP River Operations	57	0.14	62	0.15
Generation & Marketing	20	0.05	13	0.03
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	1,285	3.20	1,299	3.20

2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

Dark Spread Comparison



Coal Purchases:
2009: 95+%
2010: 85+%

Del. Coal Prices:
2007A: $36.58/ton
2008E: $46.82/ton

2009 estimated increase: 12%-15%

- Coal price represents standard NYMEX contract specifications with a heat content of 12,000 Btus/lb
- 10,000 heat rate used for conversion
- Coal and peak electricity prices reflect market prices for calendar year 2009 delivery on the business dates given above

DC Cook Unit 1 Update

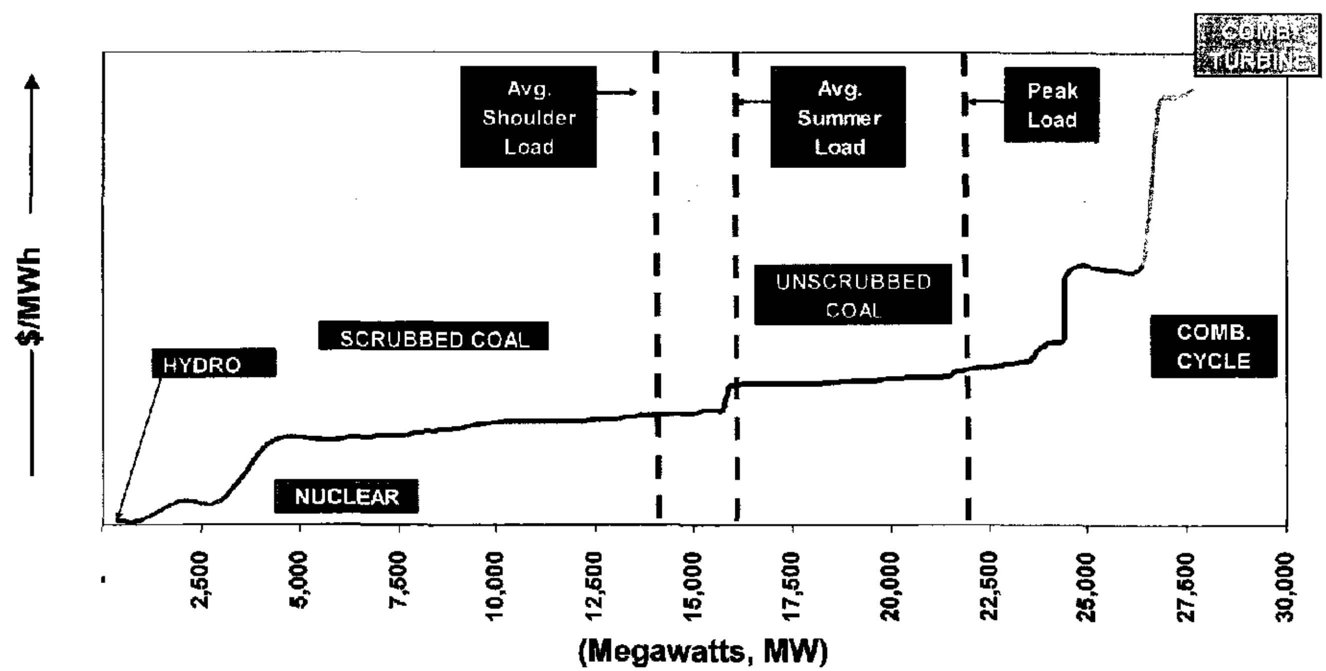
- Status
  - Off-line since September 20 due to vibrations caused by a broken turbine blade, which damaged the main turbine
  - Turbines and turbine rotors being assessed for repair vs. replace
  - Return to service schedule and cost estimates available in late November
- No incremental O&M or capital expected; Vendor warranties and property insurance will cover repair costs
- Active fuel clauses in Indiana and Michigan will allow for recovery of the fuel differential from retail customers
- Planned outage schedules have been adjusted to partially mitigate the impact of the Cook Unit 1 outage on available generation output for OSS purposes
- Accidental outage insurance of $3.5MM per week commencing in mid-December mitigates financial impact

We will provide an update on Cook once we receive additional information from our vendors

AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- *Shoulder periods offer the flexibility to reschedule planned outages.*

Typical AEP Supply Stack



With the loss of Cook 1 this fall season, a planned outage on a scrubbed coal unit was cancelled, leaving the supply stack in roughly the same position for off-system sales

Pension and OPEB Estimate

- The Pension plan and OPEB funds investment returns are each down about 25% YTD as of October 16, 2008. The drop in assets is mitigated slightly by a corresponding decrease in plan liability caused by a higher discount rate (from 6% to 7% for pensions and from 6.25% to 7.25% for OPEB).
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- As of October 16, 2008, we expect 2009 pension expense to increase $10MM over 2008 and the estimated OPEB expense to increase $30MM year over year.
- These increases are reflected in our current guidance.
- We are currently not expecting any mandatory contributions to pension in 2009.

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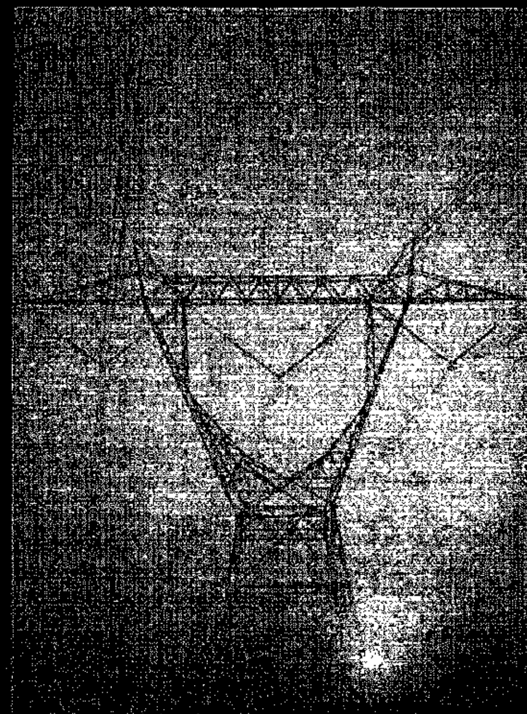
AEP AMERICAN® ELECTRIC POWER

2008 Fact Book



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Company Overview

Fall EEI 2008

Company Overview

OUR FOCUS IS OUR CORE
DOMESTIC UTILITY BUSINESS OPERATIONS

American Electric Power Company, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, *Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating* companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Utility Divisions	Electric Utility Subsidiaries
AEP Ohio	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	Texas Central Company Texas North Company
Appalachian Power	Appalachian Power Kingsport Power
Indiana Michigan Power	Indiana Michigan Power
Kentucky Power	Kentucky Power
Public Service Company of Oklahoma	Public Service Company of Oklahoma
Southwestern Electric Power Co.	Southwestern Electric Power Co.

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Almost 39,000 megawatts of generating capacity in 3 RTOs (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 212,781 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 9.000 railcars
- own and/or operate over 2,900 hopper barges and 80 towboats
- operate one active coal-handling terminal with 20 millions tons of capacity

We consume approximately 76 million tons of coal annually.

Company Strategy

Business Strategy

AEP's mission is to bring comfort to our customers, support business and commerce and build strong communities. Our strategy to achieve our mission is to grow our core utility business at a moderate and steady rate through major investment in our current utility business supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated transmission company for the pursuit of new major interstate projects. 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.

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Our Focus

Deliver value to our investors

- **Continue to invest in our core utility business to enable future earnings growth while improving both our earned and allowed ROEs across all operating companies**
- **Optimize the regulatory outcome for all operating companies**
- **Maximize the output of our generation fleet and optimize our off-system sales**
- **Continue to develop our transmission opportunities**
- **Continue active involvement in climate change policy**

AEP Service Territory

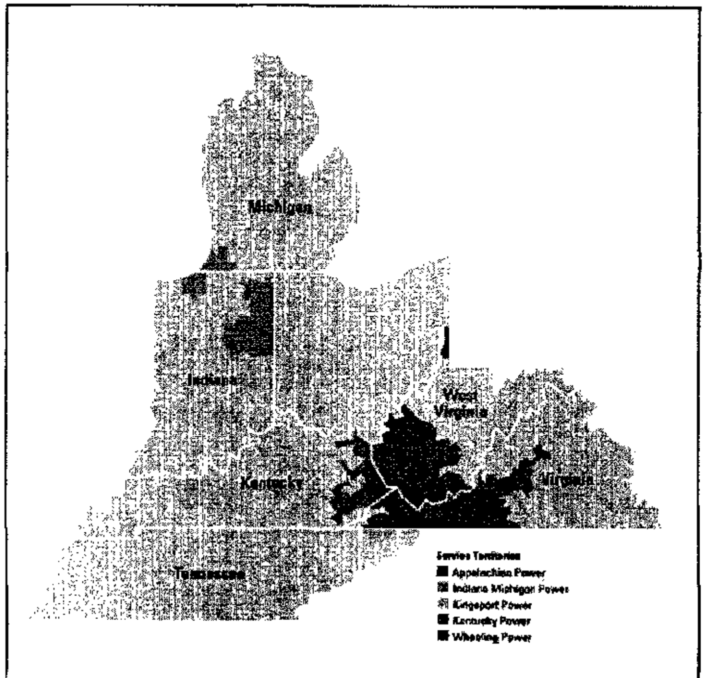
AEP EAST OPERATING COMPANIES

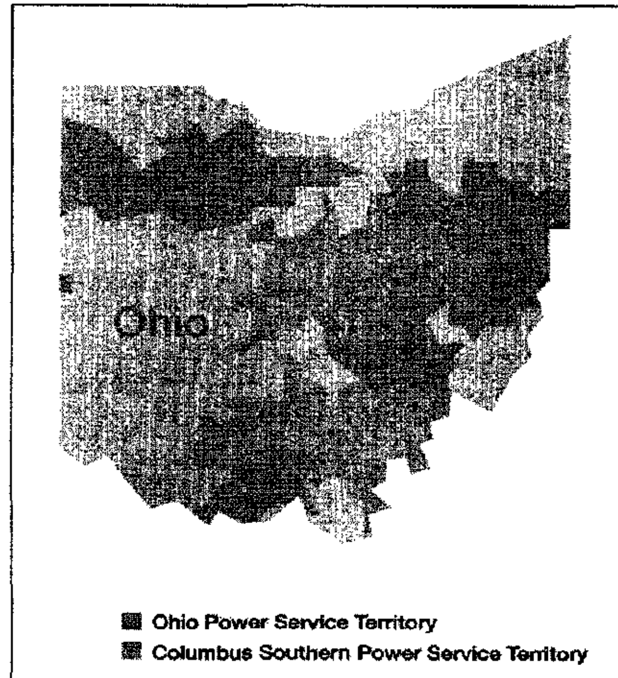
EAST REGULATED UTILITIES

Appalachian Power Company
Indiana Michigan Power Company
Kingsport Power Company
Kentucky Power Company
Wheeling Power Company

AEP OHIO

Columbus Southern Power Company
Ohio Power Company

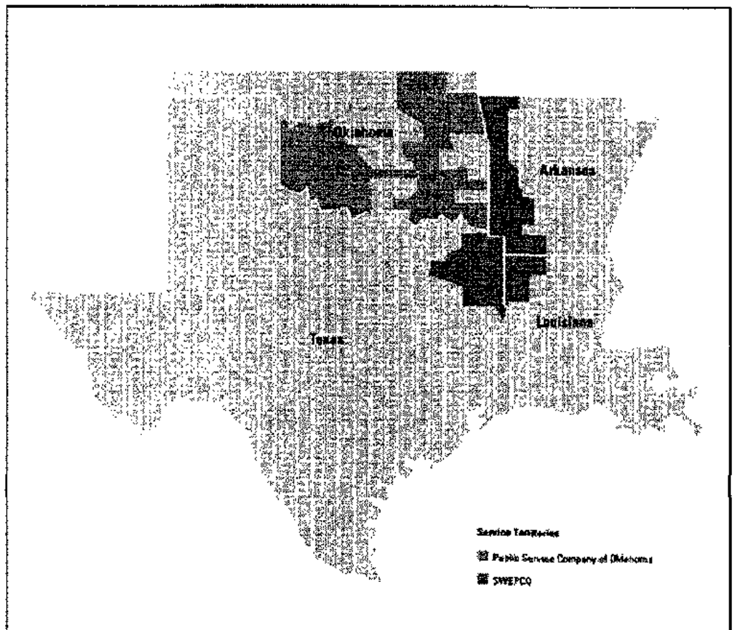


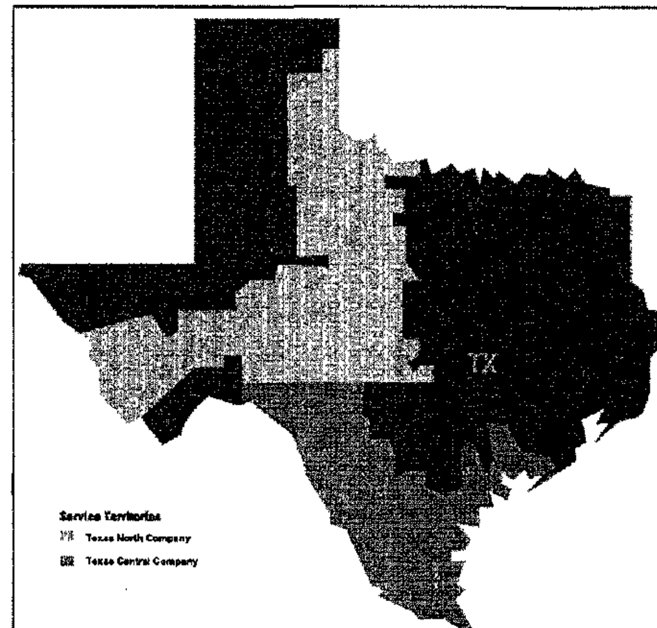


AEP Service Territory

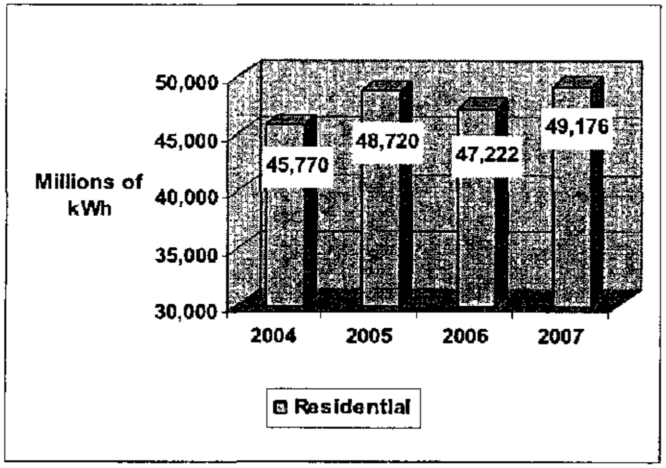
AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES	AEP TEXAS
Public Service Company of Oklahoma	Texas Central Company
Southwestern Electric Power Company	Texas North Company



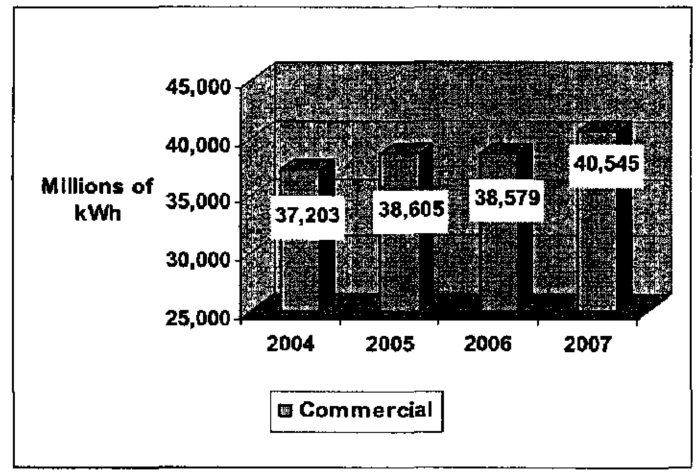


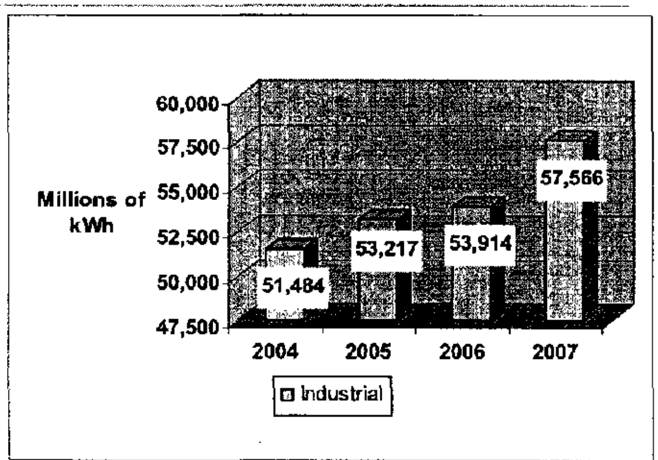
Utility Operations - Load



3 Yr. Compound Annual Residential Load Growth at 2.42%

3 Yr. Compound Annual Commercial Load Growth at 2.91%





3 Yr. Compound Annual Industrial Load Growth at 3.79%

Note: Figures do not include Texas Retail and Miscellaneous Other

2007 Retail Revenue

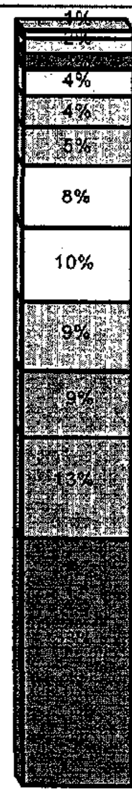
CUSTOMER PROFILE

AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

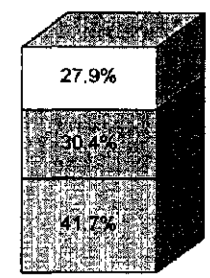
PERCENTAGE OF AEP SYSTEM RETAIL REVENUES

Tennessee	1%
Michigan	2%
Arkansas	2%
Kentucky	4%
Louisiana	4%
Texas SPP	5%
Texas ERCOT	8%
Virginia	9%
Indiana	9%
West Virginia	10%
Oklahoma	13%
Ohio	[illegible]



Retail Revenue Composition by Customer Class**

Industrial	27.9%
Commercial	30.4%
Residential	41.7%



Source: Form 10-K
*Note: Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.
**Note: Figures do not include Other Retail Sales

Utility Operations

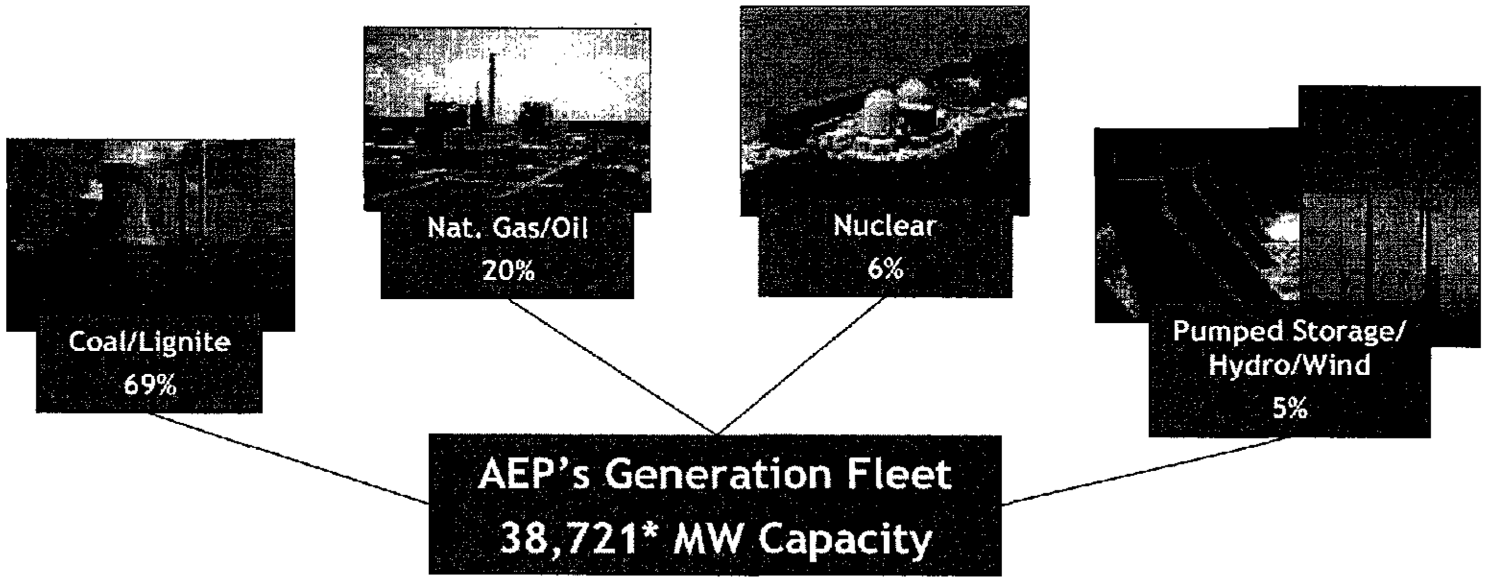
Generation

AEP has approximately 39,000 megawatts of generating capacity in 3 RTOs. AEP owns all or portions of 60 major generating plants, which include coal/lignite, natural gas, nuclear, wind projects and hydroelectric facilities.

AEP operates generating capacity in its internal power pool under an economic dispatch system[1]. AEP's power pool's competitive, largely coal-based production costs are among the lowest in the nation. AEP's power production costs are also kept relatively low by its reliance primarily on fossil fuel (gas and coal), with only a small overall nuclear dependence.

[1] Economic dispatch of a generating system utilizes the lowest-cost generating units to meet electric demand at any point in time.

Domestic Generation Fleet



* Includes 270 MW of mothballed/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
APCo	734	97	383	106	0	3,302	0	23	1,079	787	0	230	0	6,741
CSP	0	0	884	0	0	893	0	0	467	0	59	0	113	2,416
I&M	615	0	1,614	0	0	1,665	0	0	711	0	0	739	0	5,344
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	30
KPCo	258	0	8	0	46	320	0	0	544	55	0	3	0	1,234
OPCo	509	0	909	0	0	2,464	0	0	2,169	0	0	365	112	6,528
PSO	0	0	579	34	8	2,149	10	0	812	0	0	0	0	3,592
SWEPCo	0	0	660	0	228	1,195	42	0	1,405	0	0	0	0	3,530
TCC	0	0	641	0	0	2,453	0	0	1,740	0	0	0	0	4,834
TNC	0	0	223	0	0	1,586	14	0	2,699	0	0	0	0	4,522
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	288
Total	**2,116**	**113**	**5,910**	**140**	**282**	**16,202**	**66**	**23**	**11,717**	**842**	**59**	**1,364**	**225**	**39,059**

State Level (Circuit Miles)

State	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
														0
Arkansas	0	0	28	0	228	168	42	0	461	0	0	0	0	927
Indiana	600	0	1,380	0	0	1,426	0	0	412	0	0	591	0	4,409
Kentucky	258	0	8	0	46	320	0	0	544	55	0	3	0	1,234
Louisiana	0	0	105	0	0	248	0	0	233	0	0	0	0	586
Michigan	16	0	234	0	0	239	0	0	299	0	0	148	0	936
Ohio	509	0	1,793	0	0	3,358	0	0	2,636	0	59	365	225	8,945
Oklahoma	0	0	625	34	8	2,174	10	0	812	0	0	0	0	3,663
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	275
Texas	0	0	1,345	0	0	4,793	14	0	5,151	0	0	0	0	11,303
W. Virginia	384	17	323	0	0	1,602	0	23	457	739	0	89	0	3,634
Virginia	349	96	69	15	0	1,720	0	0	709	48	0	141	0	3,147
Total	**2,116**	**113**	**5,910**	**140**	**282**	**16,202**	**66**	**23**	**11,717**	**842**	**59**	**1,364**	**225**	**39,059**

Note: Transmission line circuit miles are current as of 12/31/07

Distribution Line Detail

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,522	KGPCO	1,522
Virginia	30,005	KYPCO	9,848
W. Virginia	21,339	APCO	49,860
Kentucky	9,848	OPCO	26,396
Ohio	45,110	CSP	18,714
Michigan	5,247	I&M	20,089
Indiana	14,842	WPC	1,484
Texas	51,320	TCC	29,038
Oklahoma	21,622	TNC	13,772
Arkansas	4,442	PSO	21,622
Louisiana	7,484	SWEPCO	20,436
Total	**212,781**	**Total**	**212,781**

* Includes approximately 28,800 miles of underground circuit miles

Note: Distribution line circuit miles are current as of 12/31/2007

The Texas Panhandle Area was transferred from Texas North (Abilene District) to SWEPCO (Texarkana District) during 2007.

Musser Companies takeover included in APCO WVA mileage numbers.

Utility Operations

PROPERTY, PLANT & EQUIPMENT DETAIL ($ MILLIONS)

Property Plant and Equipment	Original Cost	AEP Accumulated D&A	Net Utility Plant
Electric:			
Production	$ 20,948	$ 9,200	$ 11,748
Transmission	7,734	2,417	5,317
Distribution	12,561	3,332	9,229
Other (including coal mining & nuclear fuel)	3,633	1,708	1,925
Work in Progress	3,516	(54)	3,570
Total	**$ 48,392**	**$ 16,603**	**$ 31,789**

Source: Company information as of 9/30/08

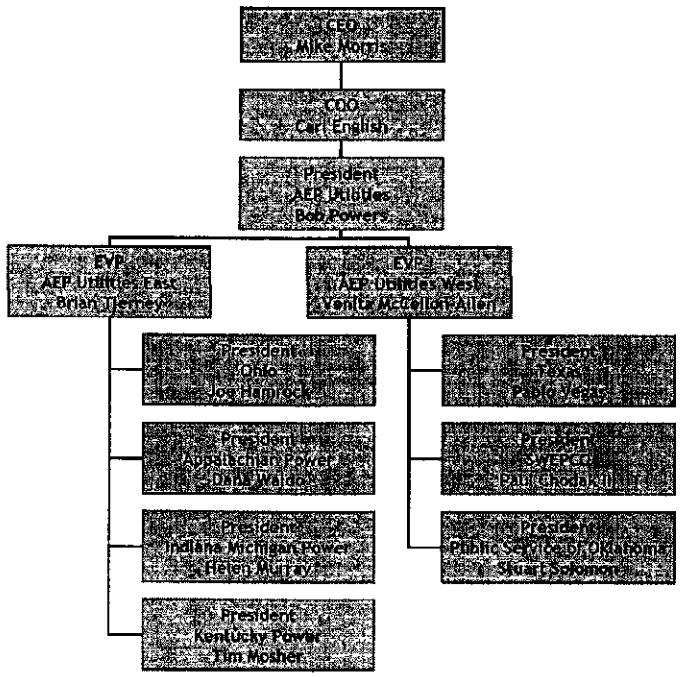
Operating Company Overview

Operating Company Overview

- Organizational Structure
- AEP East Regional Utilities
- AEP West Regional Utilities

Fall EEI 2008

Organizational Structure




Mike

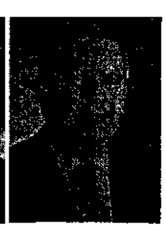

Carl


Bob


Brian


Venita


Joe

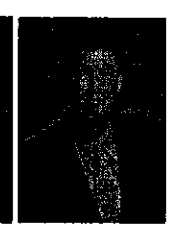

Dana


Helen


Tim


Pablo


Paul


Stuart

Senior management close to customers and regulators

AEP East Regional Utilities

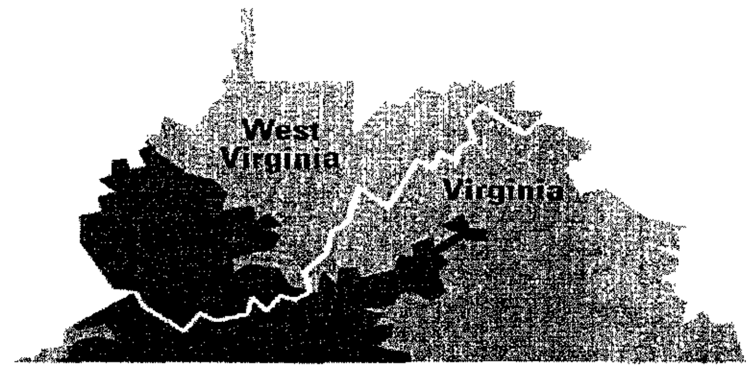
Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 956,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2007, APCo and its wholly owned subsidiaries had 2,497 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products



Total Customers at 12/31/07:

• Residential	815,000
• Commercial	130,000
• Industrial	4,000
• Other	7,000
Total	956,000

Generating Capacity	6,290 MW

Generating Capacity by Fuel Mix:

• Coal:	80.9%
• Hydro/Pump:	10.8%
• Nat Gas:	8.3%

Transmission Miles	6,741
Distribution Miles	49,860

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576	3,122,556	2,099,784	5,222,340
% of Capitalization Per Balance Sheet	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%	59.8%	40.2%	100.0%
Adjusted Capitalization	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576	3,133,657	2,099,784	5,233,441
% of Adjusted Capitalization	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%	59.9%	40.1%	100.0%
FFO Interest Coverage			3.7			3.9			3.1
FFO Total Debt			12.4%			14.4%			12%

2007 Financial Data * (in thousands)

Revenue	$	2,607,000
% of AEP Retail		18%
Net Income	$	54,000
Capital Expenditure	$	746,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	8,161,499
Net Plant Assets	$	6,495,352
Cash	$	1,987

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Appalachian Power

APCo Generation Production Statistics - 2005 - 2007				
Production Stat	2005	2006	2007	Three Year Average
MWh Produced	32,949,364	31,494,581	32,588,773	32,344,239
Coal Consumption (tons burned)	13,187,986	12,619,910	12,828,218	12,878,704

Operating Information			
2007 retail electric sales in megawatt-hours	33,875,411	2007 firm wholesale sales in megawatt-hours	3,435,670
Average cost per kilowatt-hour (residential)	6.36 cents	2007 System Peak - February 6	8,003 MW

Appalachian Power Plants (Winter Capacity)			
Name	Location	Nominal Megawatt Capacity	Fuel
Buck #1,2,3	Ivanhoe, Virginia	5	Hydro
Byllesby #1,2,3,4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1,2,3,4	Radford, Virginia	28	Hydro
Clinch River #1,2,3	Carbo, Virginia	705	Coal
Glen Lyn #1,2	Glen Lyn, Virginia	335	Coal
Leesville #1,2	Leesville, Virginia	9	Hydro
Niagara #1,2	Roanoke, Virginia	1	Hydro
Reusens #1,2,3,4,5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1,2,3,4,5	Penhook, Virginia	586	Pump
John E. Amos #1,2 *(APCo owns 1/3 of Unit 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,320	Coal
Kanawha River #1,2	Glasgow, West Virginia	400	Coal
London #1,2,3	Montgomery, West Virginia	12	Hydro
Marmet #1,2,3	Marmet, West Virginia	11	Hydro
Philip Sporn #1,3	New Haven, West Virginia	300	Coal
Winfield #1,2,3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA

INVESTOR OWNED UTILITIES *

West Virginia	Customers
APCo	435,765
Allegheny	500,051

Virginia	Customers
APCo	509,315
Dominion Virginia	2,211,200
Allegheny	98,574
Kentucky Utilities	29,963
Potomac	22,282

Tennessee	Customers
APCo	46,208

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

- **Top 10 Customers = 50% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

TYPICAL BILL COMPARISON **

West Virginia	$/month
APCo	64.55
AEP - Wheeling	64.55
Allegheny	72.52

Virginia	$/month
Old Dominion Power (Kentucky Utilities)	68.72
APCo	71.96
Dominion Virginia	88.69
Potomac	122.92

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

MAJOR CUSTOMERS:
Century Aluminum of WV, Inc. (WV)
Felman Production (WV)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Steel of West Virginia (WV)
Goodyear Tire and Rubber (VA)
CNX Gas Company (VA)

(data for year ended December 2007)

Columbus Southern Power

President and Chief Operating Officer: Joe Hamrock

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 746,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2007, CSPCo had 1,265 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers at 12/31/07:		
• Residential		666,000
• Commercial		77,000
• Industrial		3,000
Total		746,000
Generating Capacity		3,701 MW
Generating Capacity by Fuel Mix:		
• Coal	63.4%	
• Natural Gas	36.6%	
Transmission Miles		2,416
Distribution Miles		18,714

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005 Debt	2005 Equity	2005 Total	2006 Debt	2006 Equity	2006 Total	2007 Debt	2007 Equity	2007 Total
Capitalization Per Balance Sheet	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035	1,393,423	1,164,277	2,557,700
% of Capitalization Per Balance Sheet	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%	54.5%	45.5%	100.0%
Adjusted Capitalization	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035	1,401,551	1,164,277	2,565,828
% of Adjusted Capitalization	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%	54.6%	45.4%	100.0%
FFO Interest Coverage			5.8			6.2			5.9
FFO Total Debt			24.3%			28.8%			26.9%

2007 Financial Data * (in thousands)

Revenue	$	2,043,000
% of AEP Retail		16%
Net Income	$	258,000
Capital Expenditure	$	338,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	3,949,104
Net Plant Assets	$	3,262,005
Cash	$	1,956

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Columbus Southern Power

Columbus Southern Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three Year Average**
MWh Produced	14,038,045	14,134,232	15,514,495	14,562,257
Coal Consumption (tons burned)	6,048,060	5,953,084	6,327,803	6,109,649

Operating Information

2007 retail sales in megawatt-hours	22,008,607
2007 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.81 cents
2007 System Peak - August 8	4,723 MW

Columbus Southern Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Conesville #1,2,3,4 *(Unit #4 co-owned by DP&L, Duke, CSP 43.5%)*	Conesville, Ohio	1,254	Coal
J. M. Stuart #1,2,3,4 *(Units co-owned by DP&L, Duke, CSP 26%)*	Aberdeen, Ohio	604	Coal
Wm. H. Zimmer #1 *(Co-owned by DP&L, Duke, CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #6 *(Co-owned by DP&L, Duke, CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	850	Nat Gas
J. M. Stuart #1,2,3,4 *(Units co-owned by DP&L, Duke, CSP 26%)*	Aberdeen, Ohio	3	Oil
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	507	Nat Gas

Columbus Southern Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	1,449,636
First Energy ***	1,820,036
Duke Energy Ohio	670,135
DP&L	513,074

** AEP Ohio - CSPCo = 739,424
OPCo = 710,212

*** First Energy - Toledo Edison = 265,028
CEI = 702,968
Ohio Edison = 852,040

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	80.61
AEP (CSP)	93.78
DP&L	98.54
Duke Energy Ohio	107.25
FE (CEI)	109.90
FE (Ohio Edison)	116.35
FE (Toledo Edison)	125.27

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Aluminum
Eramet Marietta, Inc.
Kraton Polymers
E I duPont de Nemours HQ
Glatfelter Company
Anheuser-Busch, Inc.
Griffin Wheel Company, Inc.

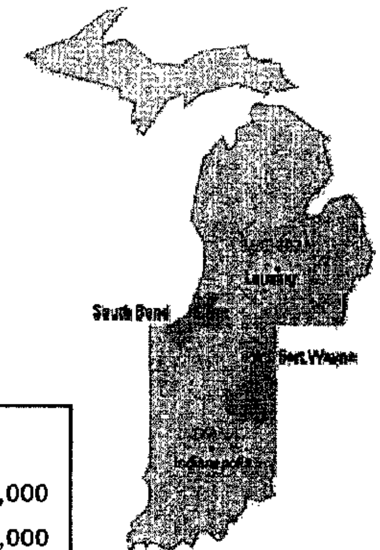
(data for year ended December 2007)

- **Top 10 customers = 59% of industrial sales**
- **Metropolitan areas account for 86% of ultimate sales**
- **238 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

Indiana Michigan Power

President and Chief Operating Officer: Helen Murray



Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 583,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2007, I&M had 2,687 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Energy Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Energy Indiana and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers at 12/31/07:	
• **Residential**	**508,000**
• **Commercial**	**68,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**583,000**
Generating Capacity	**5,821 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**51.1%**
• **Nuclear:**	**48.6%**
• **Hydro:**	**0.3%**
Transmission Miles	**5,344**
Distribution Miles	**20,089**

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829	1,612,491	1,393,779	3,006,270
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%	53.6%	46.4%	100.0%
Adjusted Capitalization	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238	2,049,215	1,393,779	3,442,994
% of Adjusted Capitalization	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%	59.5%	40.5%	100.0%
FFO Interest Coverage			4.7			4.8			4.8
FFO Total Debt			22.8%			23.9%			26.1%

2007 Financial Data * (in thousands)

Revenue	$	2,043,000
% of AEP Retail		11%
Net Income	$	137,000
Capital Expenditure	$	295,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	5,935,699
Net Plant Assets	$	3,702,117
Cash	$	1,328

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Indiana Michigan Power

I&M Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Avg.**
MWh Produced	31,535,226	31,950,768	31,604,874	31,696,956
Coal Consumption (tons burned)	7,011,370	7,947,666	7,406,506	7,455,181

Operating Information

2007 retail electric sales in megawatt-hours	19,552,126
2007 firm wholesale sales in megawatt-hours	3,555,874
Average cost per kilowatt-hour (residential)	6.83 cents
2007 System Peak - August 7	4,528 MW

Indiana Michigan Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Rockport #1,2 (includes AEG)	Rockport, Indiana	2,620	Coal
Berrien Springs #1,2,3,4,5,6,7,8,9,10,11,12	Berrien Springs, Michigan	5	Hydro
Buchanan #1,2,3,4,5,6,7,8,9,10	Buchanan, Michigan	2	Hydro
Constantine #1,2,3,4	Constantine, Michigan	1	Hydro
Elkhart #1,2,3	Elkhart, Indiana	2	Hydro
Mottville #1,2,3,4	Mottville, Michigan	1	Hydro
Tanners Creek #1,2,3,4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1,2,3,4,5,6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1,2	Bridgman, Michigan	2,191	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN INVESTOR OWNED UTILITIES *

Indiana	Customers
I & M	454,345
IP & L	466,833
NIPSCO	450,819
Duke Energy Indiana	766,165
SIGECo	145,726

Michigan	Customers
I & M	126,546
Consumers Energy	1,792,469
Detroit Edison	2,166,478

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	$/month
I & M	71.46
IP & L	73.37
Duke Energy Indiana	89.19
SIGECo	116.10

Michigan	$/month
I & M	66.09
Consumers Energy	101.79
Detroit Edison	113.12

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

- **Top 10 Customers = 47% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **204 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

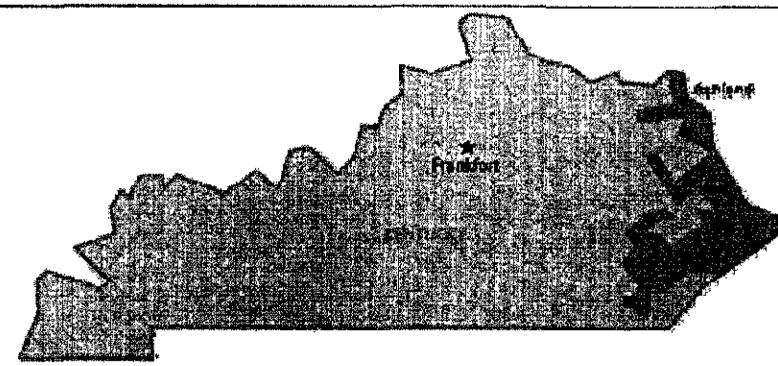
MAJOR CUSTOMERS:

Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corporation (MI)
New Energy Corp (IN)
Dock Foundry (MI)
White Pigeon Paper Company (MI)
IN TEK (IN)
The Minute Maid Company (MI)

(data for year ended December 2007)

Kentucky Power

President and Chief Operating Officer: Tim Mosher



Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2007, KPCo had 471 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

Total Customers at 12/31/07:	
• **Residential**	**144,000**
• **Commercial**	**30,000**
• **Industrial**	**1,500**
• **Other**	**500**
Total	**176,000**
Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,234**
Distribution Miles	**9,848**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	493,030	347,841	840,871	477,604	369,651	847,255	467,526	386,969	854,495
% of Capitalization Per Balance Sheet	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%	54.7%	45.3%	100.0%
Adjusted Capitalization	493,030	347,841	840,871	477,604	369,651	847,255	469,770	386,969	856,739
% of Adjusted Capitalization	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%	54.8%	45.2%	100.0%
FFO Interest Coverage			3.4			3.9			3.8
FFO Total Debt			14.0%			17.7%			17.3%

2007 Financial Data * (in thousands)

Revenue	$	588,000
% of AEP Retail		4%
Net Income	$	32,500
Capital Expenditure	$	68,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	1,385,672
Net Plant Assets	$	1,096,852
Cash	$	455

Sources: * 2007 Annual Report
** 3Q08 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Kentucky Power

Kentucky Power Generation Production Statistics - 2005-2007				
Production Stat	2005	2006	2007	Three-Year Average
MWh Produced	7,345,624	7,171,505	7,533,223	7,350,117
Coal Consumption (tons burned)	2,926,253	2,854,537	2,950,296	2,910,362

Operating Information

2007 retail electric sales in megawatt-hours	7,114,506
2007 firm wholesale sales in megawatt-hours	100,249
2007 average cost per kilowatt-hour (residential)	6.71 cents
2007 System Peak - February 6	1,808 MW

Kentucky Power Plants (Winter Capacity)			
Name	Location	Nominal Megawatt Capacity	Fuel
Big Sandy #1,2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY INVESTOR OWNED UTILITIES *

Kentucky	Customers
KPCo	175,572
Kentucky Utilities	497,939
LG & E	397,331

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	$/month
KPCo	67.89
Kentucky Utilities	73.67
LG&E	74.53
Duke Energy Kentucky	77.69

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

MAJOR CUSTOMERS:

Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Blue Diamond Coal Company
Perry County Coal Corporation
Consol of Kentucky, Inc.
Czar Coal Corporation

(data for year ended December 2007)

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **68 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

Ohio Power

President and Chief Operating Officer: Joe Hamrock

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2007, OPCo had 2,351 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

Total Customers at 12/31/07:		
• Residential		610,000
• Commercial		92,000
• Industrial		7,000
• Other		3,000
Total		712,000
Generating Capacity		8,478 MW
Generating Capacity by Fuel Mix:		
• Coal:	99.7%	
• Hydro:	0.3%	
Transmission Miles		6,528
Distribution Miles		26,396

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022	2,951,847	2,307,644	5,259,491
% of Capitalization Per Balance Sheet	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022	2,980,924	2,307,644	5,288,568
% of Adjusted Capitalization	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			6.2			6.2			4.5
FFO Total Debt			23.8%			19.7%			19.1%

2007 Financial Data * (in thousands)

Revenue	$	2,814,000
% of AEP Retail		16%
Net Income	$	268,000
Capital Expenditure	$	933,000

2008 Asset Data ** (in thousands)

		As of 9/30/08
Total Assets	$	7,684,833
Net Plant Assets	$	6,459,196
Cash	$	9,088

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Ohio Power

Ohio Power Generation Production Statistics - 2005-2007				
Production Stat	2005	2006	2007	Three Year Average
MWh Produced	52,080,585	49,341,134	54,155,697	51,859,139
Coal Consumption (tons burned)	20,382,116	19,111,071	21,234,430	20,242,539

Operating Information

2007 retail sales in megawatt-hours	27,727,742
2007 firm wholesale sales in megawatt-hours	2,293,855
Average cost per kilowatt-hour (residential)	7.72 cents
2007 System Peak - August 23	5,485 MW

Ohio Power Plants (Winter Capacity)			
Name	Location	Nominal Megawatt Capacity	Fuel
Gen. JM Gavin #1,2	Cheshire, Ohio	2,640	Coal
Mitchell #1,2	Moundsville, West Virginia	1,560	Coal
Muskingum River #1,2,3,4,5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2,4,5	New Haven, West Virginia	750	Coal
Kammer #1,2,3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	580	Coal
Racine #1,2	Racine, Ohio	26	Hydro

Ohio Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	1,449,636
First Energy ***	1,820,036
Duke Energy Ohio	670,135
DP&L	513,074

** AEP Ohio - CSPCo = 739,424
OPCo = 710,212

***First Energy - Toledo Edison = 265,028
CEI = 702,968
Ohio Edison = 852,040

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	80.61
AEP (CSP)	93.78
DP&L	98.54
Duke Energy Ohio	107.25
FE (CEI)	109.90
FE (Ohio Edison)	116.35
FE (Toledo Edison)	125.27

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Ormet Primary Aluminum Corp.
Globe Metallurgical, Inc.
Premcor Refining Group, Inc.
Linde Glass, LLC
Owens Corning Fiberglass Corp.
Marathon Ashland Petroleum, LLC
Aristech Chemical Corp.

(data for year ended December 2007)

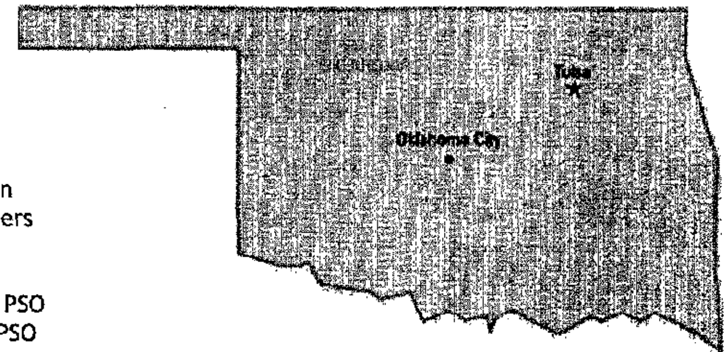
- **Top 10 customers = 50% of industrial sales**
- **Metropolitan areas account for 60% of ultimate sales**
- **136 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon



Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 525,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2007, PSO had 1,255 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy, Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers at 12/31/07:		
• Residential		451,000
• Commercial		59,000
• Industrial		7,000
• Other		8,000
Total		525,000
Generating Capacity		4,581 MW
Generating Capacity by Fuel Mix:		
• Coal:	22.2%	
• Natural Gas:	77.2%	
• Oil:	0.6%	
Transmission Miles		3,592
Distribution Miles		21,622

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	646,954	553,859	1,200,813	746,321	590,700	1,337,021	918,316	646,160	1,564,476
% of Capitalization Per Balance Sheet	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%	58.7%	41.3%	100.0%
Adjusted Capitalization	646,954	553,859	1,200,813	746,321	590,700	1,337,021	922,343	646,160	1,568,503
% of Adjusted Capitalization	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%	58.8%	41.2%	100.0%
FFO Interest Coverage			2.8			6.0			2.6
FFO Total Debt			9.5%			27.2%			9.2%

2007 Financial Data * (in thousands)

Revenue	$	1,396,000
% of AEP Retail		13%
Net Loss	$	(24,000)
Capital Expenditure	$	315,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	2,971,827
Net Plant Assets	$	2,430,979
Cash	$	2,244

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Average**
MWh Produced	15,375,848	15,139,848	14,439,801	14,985,166
Coal Consumption (tons burned)	4,353,364	4,421,396	4,102,943	4,292,568

Operating Information

2007 retail electric sales in megawatt-hours	17,910,740
2007 firm wholesale sales in megawatt-hours	10,536
Average cost per kilowatt-hour (residential)	8.10 cents
2007 System Peak - August 13	4,175 MW

Oklahoma Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Tulsa #1,2,3	Tulsa, Oklahoma	423	Nat Gas, Oil
Riverside #1,2,3,4	Jenks, Oklahoma	1,081	Nat Gas, Oil
Northeastern #1,2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern #1,2,3,4,5	Anadarko, Oklahoma	627	Nat Gas, Oil
Comanche #1,2,3	Lawton, Oklahoma	289	Nat Gas, Oil
Weleetka #1,2,3	Weleetka, Oklahoma	199	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	911	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

OKLAHOMA INVESTOR OWNED UTILITIES *

Oklahoma	Customers
PSO	516,875
OG&E	688,021

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	$/month
OG&E	74.21
PSO	79.43
Empire	90.89

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

MAJOR CUSTOMERS:

Anchor Stone
Weyerhaeuser Valliant Company
Sheffield Steel
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
American Airlines
Sun Refining
Terra Nitrogen
Sinclair
Explorer Pipeline Company

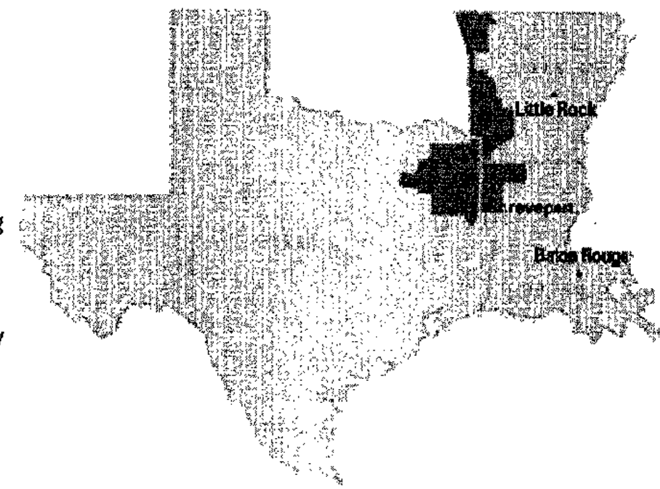
(data for year ended December 2007)

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

Southwestern Electric Power

President and Chief Operating
Officer: Paul Chodak III



Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 467,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2007, SWEPCo had 1,578 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

Total Customers at 12/31/07:		
• Residential		394,500
• Commercial		65,000
• Industrial		7,000
• Other		500
Total		467,000
Generating Capacity		4,857 MW
Generating Capacity by Fuel Mix:		
• Coal:	38.0%	
• Natural Gas:	44.7%	
• Lignite:	17.3%	
Transmission Miles		3,530
Distribution Miles		20,436

PRINCIPAL INDUSTRIES SERVED:
Oil and gas extraction
Paper products
Food processing
Primary metals

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	776,529	787,078	1,563,607	936,929	825,899	1,762,828	1,199,068	977,652	2,176,720
% of Capitalization Per Balance Sheet	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%	55.1%	44.9%	100.0%
Adjusted Capitalization	776,529	787,078	1,563,607	936,929	825,899	1,762,828	1,299,388	977,652	2,277,040
% of Adjusted Capitalization	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%	57.1%	42.9%	100.0%
FFO Interest Coverage			3.8			5.9			3.5
FFO Total Debt			18.1%			28.9%			13.7%

2007 Financial Data * (in thousands)

Revenue	$ 1,483,000
% of AEP Retail	11%
Net Income	$ 66,000
Capital Expenditure	$ 505,000

2008 Asset Data ** (in thousands)

	As of 9/30/08
Total Assets	$ 4,126,456
Net Plant Assets	$ 3,330,288
Cash	$ 2,752

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Average**
MWh Produced	20,167,754	19,961,798	19,673,059	19,934,203
Coal/Lignite Consumption (tons burned)	12,420,979	12,180,786	12,393,538	12,331,768

Operating Information

2007 retail electric sales in megawatt-hours	17,287,236
2007 firm wholesale sales in megawatt-hours	5,771,986
Average cost per kilowatt-hour (residential)	7.52 cents
2007 System Peak - August 14	4,924 MW

SWEPCO Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Mattison #1,2,3,4	Tontitown, Arkansas	346	Gas
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1,2,3,4	Mooringsport, Louisiana	278	Gas
Dolet Hills #1 *(Own 40%; operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2,3,4,5	Longview, Texas	486	Gas
Wilkes #1,2,3	Avlinger, Texas	897	Gas
Welsh #1,2,3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN INVESTOR OWNED UTILITIES *

Arkansas	Customers
SWEPCo	111,109
Entergy AR	681,298

Louisiana	Customers
SWEPCo	174,213
CLECO	265,556
Entergy	1,140,194

Texas	Customers
SWEPCo	168,180
El Paso	262,428
SPSCo	277,632
Entergy	382,202

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	$/month
OG&E	63.04
SWEPCo	65.56
Empire District	76.18
Entergy AR	97.02

Louisiana	$/month
SWEPCo	66.39
Entergy LA	86.80
Entergy NO	101.20
Entergy Gulf St	104.56
CLECO	115.08

Texas	$/month
SWEPCo	60.11
SPSCo	83.55
El Paso	112.96
Entergy	113.36

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

- **Top 10 customers = 54% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **80 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

MAJOR CUSTOMERS:

Lone Star Steel Company (TX)
Big Three Industrial Gas (TX)
UOP, LLC (LA)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Letourneau (TX)
Superior Industries (AR)
Tyson Foods, Inc. (AR)

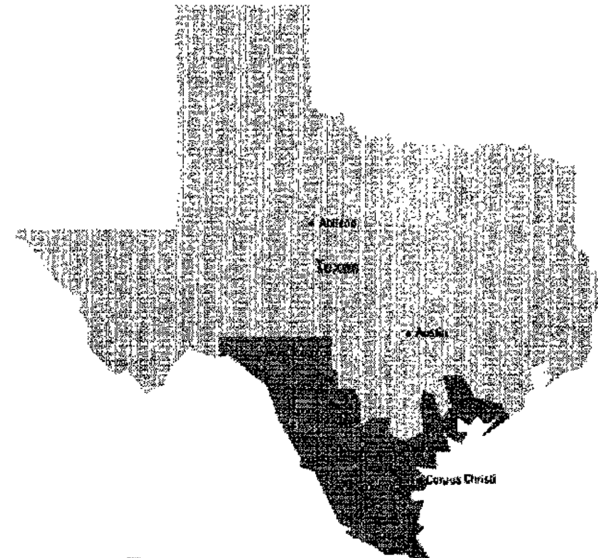
(data for year ended December 2007)

AEP Texas Central Company

President and Chief Operating Officer: Pablo Vegas

AEP Texas Central Company (TCC)

(organized *in Texas in 1945*) is *engaged* in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 753,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2007, TCC had 1,195 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.



MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Refinery West
Formosa
Javelina Refinery
Equistar Bay City

(data for year ended December 2007)

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 *customers* = 37% *of* industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 85)**

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2007)

Total Customers at 12/31/07: (Based on electric meters)	
• Residential	642,000
• Commercial	104,000
• Industrial	5,000
• Other	2,000
Total	753,000
Transmission Miles	4,834
Distribution Miles	29,038

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651	2,937,553	465,115	3,402,668
% of Capitalization Per Balance Sheet	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%	86.3%	13.7%	100.0%
Adjusted Capitalization	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843	665,544	465,115	1,130,659
% of Adjusted Capitalization	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%	58.9%	41.1%	100.0%
FFO Interest Coverage			1.4			2.0			3.7
FFO to Total Debt			2.6%			13.0%			24.8%

2007 Financial Data * (in thousands)

Revenue	$	809,000
% of AEP Retail		7%
Net Income	$	59,000
Capital Expenditure	$	222,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	5,131,177
Net Plant Assets	$	2,487,543
Cash	$	203

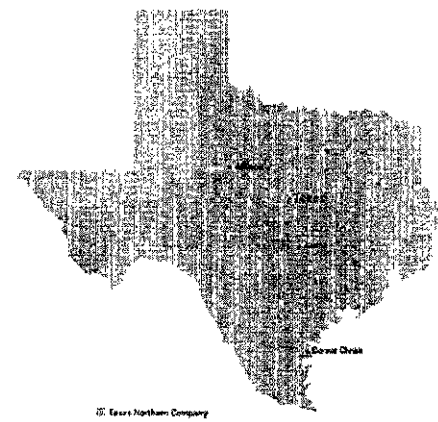
Sources: * 2007 Annual Report
** 3Q08 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

AEP Texas North Company

President and Chief Operating Officer: Pablo Vegas

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 184,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2007, TNC had 373 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.



MAJOR CUSTOMERS:

TXN
Zoltec Corporation
Tyson Foods, Inc.
Kinder Morgan
EBAA Iron

(data for year ended December 2007)

PRINCIPAL INDUSTRIES SERVED:

Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- *Top 10 customers = 37% industrial* **sales* ($)**
- **Metropolitan areas account for 60% ultimate sales**
- **8 persons per square mile (U.S. = 85)**
  - Industrial % is in terms of wires revenues

(data for 12 months ended December 2007)

Total Customers at 12/31/07:
(Based on electric meters)

• Residential	144,000
• Commercial	30,000
• Industrial	5,000
• Other	5,000
Total	184,000

Generating Capacity		377 MW
Oklaunion Plant - Vernon, TX (excludes 270 MW of decommissioned plants)		
Generating Capacity by Fuel Mix:		
• Coal:	58.3%	
• Gas:	40.5%	
• Oil:	1.2%	
Transmission Miles		4,522
Distribution Miles		13,772

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	276,845	316,276	593,121	276,936	308,705	585,641	302,386	334,244	636,630
% of Capitalization Per Balance Sheet	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%	47.5%	52.5%	100.0%
Adjusted Capitalization	276,845	316,276	593,121	268,785	308,705	577,490	303,682	334,244	637,926
% of Adjusted Capitalization	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%	47.6%	52.4%	100.0%
FFO Interest Coverage			5.0			3.7			4.7
FFO Total Debt			29.8%			17.4%			21.2%

2007 Financial Data * (in thousands)

Revenue	$	280,000
% of AEP Retail		1%
Net Income	$	39,000
Capital Expenditure	$	88,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	1,096,081
Net Plant Assets	$	954,938
Cash	$	214

Sources: * 2007 Annual Report
** 3Q08 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Regulation

- Regulatory Strategy
- Rate Case Filing Requirements
- Regulatory Activity Underway
- GridSMART Regulatory Status
- Rate Base and ROE by Operating Company
- Commission Overviews

Fall EEI 2008

Regulatory Strategy: Reduce Lag

The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Summary of Rate Case Filing Requirements

	Arkansas	Indiana	Kentucky	Louisiana	Michigan	Ohio	Oklahoma	Texas	Virginia	West Virginia	FERC
General											
Time Limitations Between Cases	No	Yes	No	No	No	No	No	No	Yes	No	No
Period of Limitation (months)	--	15	--	--	--	--	--	--	See note 1	--	--
Pancaking Permitted?	No	No	No	Yes	No	Limited	Yes	No	No	No	Yes
Notice of Intent											
Prior PSC Notice Required?	Yes	Yes	Yes	No	Optional	Yes	Yes	Yes	Yes	Yes	No
Notice Period (days)	60	Varies	28	N/A	45	30	45	30	60	30	N/A
Case Components											
Test Year	Partially Projected	Historical	Forecast Optional	Historical	Forecast Optional	Partially Projected	Partially Projected	Historical	Historical	Historical	Forecast Optional
Other											
Rates Effective Subject to Refund	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes
Approx # of Months after Filing to implement rates subject to refund	10	--	6	--	Varies	9	6	5	5	--	2 or 7

Note 1: Post 1/1/09 no interim rates provided and rate cases must be filed no less than biennially; historical test year used.

Regulatory framework inherently produces recovery and return lag.

Regulatory Activity Underway

- ☐ AEP Ohio ESP Filing
- ☐ I&M - Indiana Base Rate Case
- ☐ PSO - Oklahoma Base Rate Case
- ☐ APCo - Virginia Base Rate Case
- ☐ SWEPCo Stall Plant Filings in Arkansas
- ☐ SPP OATT Formula Rate Filing
- ☐ PJM OATT Formula Rate Filing

Regulatory Activity Underway

AEP Ohio Electric Security Plan Filing

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART℠ Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony was filed October 31, Staff testimony was filed November 7 and the public hearing commences on November 17, 2008. We anticipate an order in the first quarter of 2009.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $125.6 million ($80.1 million in base revenues and $45.6 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	1,999.1 *
Rate of Return		8.10%
Operating Income Requirement	$	161.9
Pro-Forma Operating Income	$	113.1
Difference	$	48.8
Revenue Conversion Factor		1.64
Revenue Deficiency	$	80.1
Reliability Enhancement Tracker	$	28.4
DSM / EE Tracker	$	4.4
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	44.4
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	125.6

* rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Required Rate Relief - Company Position (2/29/08) ($ in millions)

Rate Base	$	1,545.2 *
Rate of Return		8.64%
Operating Income Requirement	$	133.5
Pro-Forma Operating Income	$	53.0
Difference	$	80.5
Revenue Conversion Factor		1.647045
Total Required Rate Relief	$	132.6

* rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates were effective on October 28, 2008, subject to refund with interest. On October 29, 2008, a settlement agreement was presented to the SCC for its consideration. The settlement allows for a revenue increase of $168MM based on a 10.2% ROE. We await a final order. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1 *
Rate of Return		8.52%
Operating Income Requirement	$	205.7
Adjusted Operating Income	$	79.2
Difference	$	126.5
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	207.9

* rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Regulatory Activity Underway

SPP OATT Formula Rate Filing (Docket #:ER07-1069-000)

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing (Docket #:ER08-1329-000)

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is \$507MM and the new revenue requirement requested is \$606MM. Approximately \$31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to March 1, 2009, with rates subject to refund.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

<u>Arkansas</u>

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the fourth quarter of 2008.

<u>Louisiana</u>

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an application to purchase, operate, own and install peaking, intermediate and baseload generating facilities. The peaking facility has been addressed and the intermediate facility has been approved. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

<u>Texas</u>

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued its order approving construction of the plant on August 12, 2008, with a cost cap of $1.52 billion and a cap on carbon dioxide at $28/ton through 2030. This order is currently under appeal in Texas.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- ❑ Proceeding is pending.

Louisiana

- ❑ On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- ❑ PSC approval was granted on September 10, 2008.
- ❑ Air permit received on March 20, 2008.

Texas

- ❑ PUCT order approving plant was issued on March 8, 2007.

gridSMART^{SM} Evolution - AEP East

	State Policy	AEP Action Plans
AEP OHIO A unit of American Electric Power	SSB 221 provides targets and provisions for DSM/EE programs and supports infrastructure modernization.	Filed an Electric Security Plan (2008) which includes a model city pilot in NE Columbus and addresses DSM/EE programs. New 2 MW NaS battery in Bluffton will demonstrate use of storage to enhance a sub-transmission system.
AEP APPALACHIAN POWER A unit of American Electric Power	Legislative interest in Virginia beginning to drive regulatory activity in EE/DSM.	New 2 MW NaS battery in West Virginia will test dynamic islanding - supplying electricity while disconnected from the grid. AMR investments in Virginia and West Virginia will defer new AMI for several years. EE/DSM potential study initiated.
AEP KENTUCKY POWER A unit of American Electric Power	Kentucky's commission rules regarding DSM/EE programs are the model we seek in other states.	Existing programs are focused on low-income weatherization and heat pump programs for mobile homes with favorable recovery. AMR investment will defer new AMI for several years.
AEP INDIANA MICHIGAN POWER A unit of American Electric Power	Pending DSM filing in Indiana; rules being finalized. EE/DSM legislative goals recently established in Michigan.	Broadly focused South Bend Pilot includes AMI, distribution automation, demand response, pre-paid meters. NaS battery installation in IN in 2008 to demonstrate storage with intermittent wind.

The eastern states are evolving in their positions regarding demand side management, energy efficiency and AMI investments.

gridSMART^{SM} Evolution - AEP West

	State Policy	AEP Action Plans
AEP TEXAS A unit of American Electric Power	Current legislation allows concurrent cost recovery of DSM/EE programs and performance incentives for exceeding goals. Legislature expecting distribution service providers in ERCOT to file plans for smart meter deployment.	Implementing aggressive DSM/EE programs to achieve legislatively mandated targets of 15% and 20% to reduce growth in demand in 2008 & 2009 respectively. A deployment plan for smart meters was initiated as of 10/31/08.
AEP PUBLIC SERVICE COMPANY OF OKLAHOMA A unit of American Electric Power	DSM proceedings currently underway. Heavily involved with Commission regarding rulemaking. Favorable recovery provisions proposed.	Conducting Distribution Automation pilot in South Tulsa. In process of implementing quick start DSM/EE programs.
AEP SOUTHWESTERN ELECTRIC POWER COMPANY A unit of American Electric Power	DSM/EE program costs are recoverable thru a rider in Texas and Arkansas and base rates in Louisiana. No current statutory support for AMI outside of Texas footprint.	Implementing aggressive EE/DSM programs to achieve targets of 15% and 20% (respectively) to reduce growth in demand in 2008 & 2009 in Texas. Continue quick-start DSM/EE in Arkansas. Submitted EE Potential Study to Louisiana Commission in October 2008.

Texas currently has the most progressive legislative stance with regards to supporting AMI. PSO and SWEPCo have active DSM/EE programs with Distribution Automation pilots proposed in each state.

Approved Rate Bases & ROEs and Current Rate Case Requests

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo-Virginia	$2,022MM	10.00%	10/2/2006
APCo-West Virginia	$1,656MM	10.50%	7/28/2006
Kentucky	$858MM	10.50%	3/31/2006
I&M-Indiana	$1,805MM	12.00%	11/19/1993
I&M-Michigan	$268MM	13.00%	4/1/1991
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo-Louisiana	$577MM	10.565%	8/1/2008
SWEPCo-Arkansas	$408MM	10.75%	9/23/1999
SWEPCo-Texas	$474MM	15.70%	2/15/1983
TCC-Texas	$1,566MM	9.96%	6/1/2007
TNC-Texas	$530MM	9.96%	6/1/2007

*** - represents midpoint of the ROE range approved in the formula rate case settled in April 2008.**

Rate Case Requests on File

Jurisdiction	Requested Rate Base	Requested ROE
I&M - Indiana	$1,999MM	11.50%
PSO - Oklahoma	$1,545MM	11.25%
APCO - Virginia	$2,415MM	11.75%

Commission Overview

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 2

Qualifications for Commissioners

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.

Commissioners

Paul Suskie, Chairman (Dem.), since 2007; current term ends in 2013. Lawyer, North Little Rock, Arkansas City Attorney. Bachelor's attained at University of Central Arkansas. Juris Doctorate at University of Arkansas at Little Rock School of Law. NARUC member including Committee on Energy Resources and the Environment and Committee on Consumer Affairs.

Daryl E. Bassett, Commissioner (Rep.), since 2003; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).

Collette Honorable, Commissioner (Dem.), since 2008; current term ends in 2011. Commissioner Honorable is a member of NARUC and serves on the Electricity and Consumer Affairs Committees. She also serves on the Smart Grid Collaborative, a joint effort of NARUC and the FERC. Honorable obtained her Juris Doctorate from the University of Arkansas at Little Rock School of Law.

AEP Regulatory Status

SWEPCo-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause. Arkansas has an OSS margin sharing mechanism and allows CWIP in rate base for a plant that is placed in service within six months after the end of the test year.

Commission Overview

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 4 Years	Political Makeup: R: 3 D: 2

Qualifications for Commissioners

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

Commissioners

David L. Hardy, Chairman (Rep.), since 2005; current term will expire April 2010. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include negotiation, contracts, litigation, finance and administration. He has 35 years of regulatory experience at the state and federal levels. Bachelors degree and law degree from Indiana University.

Jeffrey L. Golc, Commissioner (Dem.), since 2007; current term will expire in 2009. Former public affairs manager for the Kroger Company. Previous Deputy Commissioner for the Indiana Bureau of Motor Vehicles and the Indiana Department of Workforce Development. Bachelors and Masters degrees in communications from Indiana University.

Larry S. Landis, Commissioner (Rep.), since 2002; current term ends June 2011. Former president of a marketing and communications agency, VP Corporate Advertising, American Fletcher National Bank. Bachelor's degrees in political science and economics.

Greg Server, Commissioner (Rep.), since 2005; current term ends 2009. Former state senator since 1981 and before that served in the Indiana House of Representatives from 1972 to 1980. Served as chair of Senate Commerce Committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility. Masters degrees in political science and counseling from Indiana State University.

David E. Ziegner, Commissioner (Dem.), since 1990; current term ends April 2011. Lawyer, staff attorney for Legislative Services Agency, General Counsel for IURC. Member, NARUC Committee on Electricity and Advisory Council of the Electric Power Research Institute. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

I&M provides retail electric service in Indiana at bundled rates approved by the IURC. Rates are set on a cost-of-service basis with a fuel recovery mechanism. A current full base rate case is in process with a final order expected in the first half of 2009. The rate case includes requests for riders related to DSM, environmental, reliability, OSS and RTO costs.

Commission Overview

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 4 Years	Political Makeup: R: 2 D:1

Qualifications for Commissioners

Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.

Commissioners

David L. Armstrong, Chairman (Dem.), since 2008; current term expires June 2011. Former practicing attorney in private practice. J.D. from University of Louisville Brandeis School of Law. Mr. Armstrong is also the former Mayor for the city of Louisville, KY (1999-2003).

John W. Clay, Vice Chairman (Rep.), since 2006; current term expires June 2009. Former deputy secretary of the Kentucky Environmental and Public Protection Cabinet. Served as executive director of the Office of Alcohol Beverage Control in the Department of Public Protection. B.A. from Georgetown College. Certified Public Accountant and member of the AICPA.

James W. Gardner, Commissioner (Rep.), since 2008; current term expires June 2012. Prior to joining the PSC Mr. Gardner was a partner at the law firm Henry Watz Gardner & Sellars PLLC where he specialized in bankruptcy law. JD degree from the University of Kentucky College of Law.

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause. Kentucky also has an OSS sharing mechanism and a monthly adjustment clause in place for DSM.

Commission Overview

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 3

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2010. B.S. Business Administration from Southern University. American University of Paris - International Trade Law - Paralegal Certificate. Former First City Court Constable for the City of New Orleans. Member of NARUC.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

James M. Field, (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Bachelor's and Juris Doctorate from Louisiana State University.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). *Member, Chamber of* Commerce.

AEP Regulatory Status

SWEPCo-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause and an OSS margin sharing mechanism. Formula rate plans are permitted in Louisiana including a potential for a partial CWIP return on new generation projects. A formula rate plan was implemented August 1, 2008.

Commission Overview

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: D: 2 I: 1

Qualifications for Commissioners

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

Commissioners

Orjiakor N. Isiogu, Chairman (Dem.), since 2007; current term expires July 2013. Former Director of the Telecommunications Division of the MPSC. Assistant Attorney General in Michigan since 1989. Undergraduate and law degree from Wayne State University.

Monica Martinez, Commissioner, (Dem.), since 2005; current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this, she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues. Bachelor's degree, University of Michigan.

Steven A. Transeth, Commissioner, (Ind.), since 2007; current term expires July 2009. Former assistant director and legal counsel for the Michigan Legislative Service Bureau, which included drafting legislation and providing legal counsel to the Michigan Senate and House of Representatives. Lawyer, private practice and with the Ingham County Prosecuting Attorney's office.. J.D. from Thomas Cooley Law School.

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active fuel clause and return on CWIP can be included in base rates.

Commission Overview

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 1 D: 2 I: 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.) , since 1999; term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee, National Governors' Association Electricity Task Force, Harvard Electricity Policy Group.

Paul A. Centolella, Commissioner, (Dem.) since 2007; term expires April 2012. Juris Doctor from the University of Michigan. From 1992-2007, worked as a senior economist in the Energy Solutions Group of Science Applications International Corporation. Former senior policy advisor and senior utility attorney for the Office of the Ohio Consumers' Counsel.

Ronda Hartman Fergus, Commissioner, (Rep.) since 1995; term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff. Member NARUC Committee on Consumer Affairs.

Valerie A. Lemmie, Commissioner, (Ind.) since 2006; term expires April 2011. Master's degree in Urban Affairs and Public Policy Planning, Washington University. Served as city manager for Cincinnati, Dayton, and Petersburg, Va. Scholar-in-residence at the Kettering Foundation. Chair of the Board of Directors of the National Academy of Public Administration.

Cheryl Roberto, Commissioner, (Dem.) since 2008; term expires April 2013. Prior to joining the PUC, Roberto was director of the City of Columbus Public Utilities Department. Before entering the public sector, Commissioner Roberto worked as an assistant attorney general for the state of Ohio. Commissioner Roberto received her B.A. with honors from Kent State University and her Juris Doctorate from the Moritz College of Law at The Ohio State University.

AEP Regulatory Status

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSP and OPCo (the Ohio Companies). The plans provided, among other things, for CSP and OPCo to raise their generation rates by 3% and 7% respectively, in 2006, 2007 and 2008 and provided for additional generation rate increases of up to 4% per year based on the Ohio Companies supporting the need for additional revenues. Distribution rates in effect at 12/31/05 are frozen for OPCo and CSP until 12/31/08. Transmission rates are currently regulated by FERC as reflected in the OATT. SB221 allows that CSP and OPCo will have active fuel clauses effective January 1, 2009. An Electric Security Plan is currently on file with the PUCO for consideration before the end of 2008. The ESP requests a 15% rate increase for all CSP and OPCo customers.

Commission Overview

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 1
Qualifications for Commissioners The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.			
Commissioners **Jeff Cloud, Chairman (Rep.)**, since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of Staff. Law degree from Oklahoma City University.			
Bob Anthony, Commissioner, (Rep.), since 1989; current term expires January 2013. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University and an M.P.A. from the Kennedy School of Government at Harvard University.			
Jim Roth, Commissioner, (Dem.), since 2007;appointed by the governor to fill the seat opened by the resignation of Commissioner Bode; current term ends January 2011. Previously served various county governments for eight years. Juris Doctorate from Oklahoma City University School of Law.			

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. PSO has an OSS margin sharing mechanism and has rider mechanisms currently approved for vegetation management and the new peaking facilities in-service in 2008.

Commission Overview

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 3
Qualifications for Commissioners The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six-year terms, which all expired in June 2008; terms are now staggered.			
Commissioners **Tre Hargett, Chairman (Rep.),** since 2008; current term expires 2012. Former Representative of House District 97. M.B.A. Memphis State University.			
Mary W. Freeman, Director (Dem.), *since 2008; current term expires June 2011. Prior legislative director for Governor Bredesen, executive assistant to* State Representative Lois DeBerry. B.A. Tennessee State University.			
Sara Kyle, Director (Dem.), since 1996; current term expires June 2012. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving director and only holdover from the previous Regulatory Authority. Law degree from Middle Tennessee State University.			
Eddie Roberson, Ph.D, Director, (Dem.), since 2006; current term expires June 2010. Former Chief of Consumer Services Division of the Regulatory Authority; also served a year as the agency's Executive Director. Served two terms on the Chattanooga City School Board. Ph.D in Public Administration from Tennessee State University.			

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Commission Overview

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Co.

Texas North Co.

Southwestern Electric Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 3

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Barry T. Smitherman, Chairman, (Rep.), since April 2004; current term expires August 2013. Attorney; Assistant DA; Public Finance Investment Banker. Received law degree from the University of Texas School of Law.

Kenneth W. Anderson, (Rep.) since September 2008; current term expires September 2011. Past Director of Governmental Appointments under Governor Perry. Prior to that Anderson served in private practice as a corporate attorney in the area of securities law and regulatory matters. He also served as a member of the Texas Securities Board from 1999-2006. Anderson holds a law degree from Southern Methodist University.

Donna Nelson, Commissioner (Rep.), since August 2008; current term expires August 2009. Nelson served as a special assistant and advisor to Governor Perry on energy, telecommunications and cable budget and policy issues. She previously served as director of the PUC telecommunication's section and legal advisor to the PUC chairman. Nelson holds a law degree from Texas Tech University.

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO). SWEPCO-TX has an active fuel pass-through clause as well as OSS margin sharing. In some circumstances, CWIP is allowed in rate base.

TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission riders provide annual recovery dependent on the level of transmission investment and ERCOT load growth rates. AFUDC is permitted in limited circumstances.

Commission Overview

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 1
Qualifications for Commissioners The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.			
Commissioners **Judith Williams Jagdmann, Chairperson, (Rep.)**, since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.			
Mark C. Christie (Rep.), since 2004; current term expires 2010. Attorney, counsel to the Speaker of the House. Lawyer, private practice. Law degree from Georgetown.			
James C. Dimitri (Dem.), since 2008; current term expires 2014. Prior to being named Commissioner, Dimitri was in private practice in Richmond. From 1994 to 2000 he served as Senior Counsel, then General Counsel at the SCC. He was an assistant Attorney General from 1983 to 1987. Dimitri received his undergraduate degree in economics from the University of Virginia and his J.D. from the Boston University School of Law in 1976.			

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. In 2007, the General Assembly passed legislation re-establishing retail rate regulation in the Commonwealth. The opportunity for one rate case exists before December 31, 2008, which was filed May 30, 2008. The new legislation provides for biennial rate reviews beginning in 2009, sharing of off-system sales margins at a rate of a minimum of 25% retained by the company effective July 1, 2007 and a post-2008 rider for DSM, renewable programs and new generation. APCo-VA is entitled to annual rate changes to recover the incremental costs it incurs for transmission and distribution system reliability and compliance with state or federal environmental laws or regulations (known as the E&R rider). APCo-VA is entitled to adjustments to fuel rates to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges.

Commission Overview

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.

Wheeling Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, Commissioner (Dem.), since 2003; term expires June 2009. Former Chief of Operations in the Governor's office. Former Chief Financial Officer of the Workers' Compensation Division of the W.V. Bureau of Employment Programs. Certified Public Accountant in West Virginia and Georgia. Bachelor's degree, West Virginia University.

Michael A. Albert, Chairman (Rep.), since 2007; term expires June 2013. Served as a member in the Business Law Department of Jackson Kelly. President and Chairman of the board of directors of the Kanawha County Public Library. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Jon W. McKinney, Commissioner (Dem.), since 2005; term expires June 2011. Currently on the board of directors of the NARUC and second VP of the Mid-Atlantic Conference of Regulated Utilities Commissioners. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable, Advantage Valle, St. Francis Hospital & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items. West Virginia also has a special construction surcharge permitted, primarily related to environmental-related construction.

Generation & Environmental

Generation & Environmental

- Units
- Generation Statistics
- New Generation
- Environmental
- Future Potential Green House Gas Regulations

Fall EEI 2008

Domestic Generation

Generation Capacity*

COMPANY	MW Capacity
AEP Generating Co	2,466
Appalachian Power Co	6,290
Columbus Southern Power	3,701
Indiana Michigan Power Co	4,501
Kentucky Power Co	1,060
Ohio Power Co	8,478
Public Service of Oklahoma	4,581
Southwestern Electric Power Co	4,857
Texas North Co**	647
OVEC Capacity***	986
Domestic IPPs	311
Wind Purchase Power Agreements	843
Total	**38,721**

*Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).

** Includes 270 MW of mothballed / retired / decommissioned generation

*** AEP owns a 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE.

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
AEP Generating Company					
Rockport	1	IN	RFC	Steam - Coal	1,320
Lawrenceburg	6	IN	RFC		1,146
					2,466
Appalachian Power Company					
Buck	3	VA	RFC	Hydro	5
Byllesby	4	VA	RFC	Hydro	8
Claytor	4	VA	RFC	Hydro	28
Leesville	2	VA	RFC	Hydro	9
London	3	WV	RFC	Hydro	12
Marmet	3	WV	RFC	Hydro	11
Niagara	2	VA	RFC	Hydro	1
Reusens	5	VA	RFC	Hydro	6
Winfield	3	WV	RFC	Hydro	15
Smith Mountain	5	VA	RFC	Pumped Storage	586
Amos	2	WV	RFC	Steam - Coal	2,033
Clinch River	3	VA	RFC	Steam - Coal	705
Glen Lyn	2	VA	RFC	Steam - Coal	335
Kanawha River	2	WV	RFC	Steam - Coal	400
Mountaineer	1	WV	RFC	Steam - Coal	1,320
Sporn	2	WV	RFC	Steam - Coal	300
Ceredo	6	WV	RFC	Natural Gas	516
					6,290
Columbus Southern Power Company					
Beckjord (CCD)	1	OH	RFC	Steam - Coal	53
Conesville (CCD)	4	OH	RFC	Steam - Coal	1,254
Picway (CCD)	1	OH	RFC	Steam - Coal	100
Stuart (CCD)	4	OH	RFC	Steam - Coal	604
Stuart (CCD)	4	OH	RFC	Oil	3
Zimmer (CCD)	1	OH	RFC	Steam - Coal	330
Waterford	4	OH	RFC	Natural Gas	850
Darby	6	OH	RFC	Natural Gas	507
					3,701
Indiana Michigan Power Company					
Berrien Springs	12	MI	RFC	Hydro	5
Buchanan	10	MI	RFC	Hydro	2
Constantine	4	MI	RFC	Hydro	1
Elkhart	3	IN	RFC	Hydro	2
Mottville	4	MI	RFC	Hydro	1
Twin Branch	6	IN	RFC	Hydro	4
Rockport	1	IN	RFC	Steam - Coal	1,300
Tanners Creek	4	IN	RFC	Steam - Coal	995
Cook	2	MI	RFC	Steam - Nuclear	2,191
					4,501

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
Kentucky Power Company					
Big Sandy	2	KY	RFC	Steam - Coal	1,060
Ohio Power Company					
Racine	2	OH	RFC	Hydro	26
Amos	1	WV	RFC	Steam - Coal	867
Cardinal	1	OH	RFC	Steam - Coal	580
Gavin	2	OH	RFC	Steam - Coal	2,640
Kammer	3	WV	RFC	Steam - Coal	630
Mitchell	2	WV	RFC	Steam - Coal	1,560
Muskingum River	5	OH	RFC	Steam - Coal	1,425
Sporn	3	WV	RFC	Steam - Coal	750
					8,478

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
Public Service Company of Oklahoma					
Tulsa	3	OK	SPP	Steam - Natural Gas	415
Tulsa	3	OK	SPP	Oil	8
Riverside	2	OK	SPP	Steam - Natural Gas	928
Riverside	2	OK	SPP	Steam - Natural Gas	150
Riverside	1	OK	SPP	Oil	3
Northeastern (1&2)	4	OK	SPP	Steam - Natural Gas	940
Northeastern	1	OK	SPP	Oil	3
Sothwestern	3	OK	SPP	Steam - Natural Gas	475
Sothwestern	2	OK	SPP	Steam - Natural Gas	150
Sothwestern	1	OK	SPP	Oil	2
Comanche	3	OK	SPP	Steam - Natural Gas	285
Comanche	2	OK	SPP	Oil	4
Weleetka	3	OK	SPP	Steam - Natural Gas	195
Weleetka	2	OK	SPP	Oil	4
Northeastern (3&4)	2	OK	SPP	Steam - Coal	910
Northeastern	1	OK	SPP	Oil	1
Oklaunion	1	TX	ERCOT	Steam - Coal	108
					4,581
Southwestern Electric Power Company					
Arsenal Hill	1	LA	SPP	Steam - Natural Gas	110
Lieberman	4	LA	SPP	Steam - Natural Gas	278
Knox Lee	4	TX	SPP	Steam - Natural Gas	486
Wilkes	3	TX	SPP	Steam - Natural Gas	897
Lone Star	1	TX	SPP	Steam - Natural Gas	50
Mattison	4	AR	SPP	Steam - Natural Gas	346
Welsh	3	TX	SPP	Steam - Coal	1,584
Flint Creek	1	AR	SPP	Steam - Coal	264
Pirkey	1	TX	SPP	Steam - Lignite	580
Dolet Hills	1	LA	SPP	Steam - Lignite	262
					4,857

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
Texas Central Company					
none					
Texas North Company					
Paint Creek (Retired)	4	TX	ERCOT	Steam - Natural Gas	238
Abilene (Retired)	1	TX	ERCOT	Steam - Natural Gas	18
Ft. Stockton (Decommissioned)	1	TX	ERCOT	Steam - Natural Gas	6
Vernon (Decommissioned)	4	TX	ERCOT	Oil	8
Oklaunion	1	TX	ERCOT	Steam - Coal	377
					647
Domestic Independent Power Projects					
Trent Mesa	100	TX	ERCOT	Wind	150
Desert Sky	107	TX	ERCOT	Wind	161
					311
Long-Term Wind Purchase Power Agreements					
Southwest Mesa		TX	ERCOT	Wind	75
Weatherford		OK	SPP	Wind	147
Blue Canyon II		OK	SPP	Wind	151
Sleeping Bear		OK	SPP	Wind	95
Camp Grove		IL	RFC	Wind	75
Fowler Ridge		IN	RFC	Wind	100
Fowler Ridge		IN	RFC	Wind	100
Beech Ridge		WV	RFC	Wind	100
					843

Generation Statistics

Net Capacity Factors	2006	2007
AEP East	64.57%	64.26%
Coal	70.34%	71.89%
Super Critical*	73.36%	73.00%
Sub-Critical*	61.00%	68.44%
Gas	2.58%	7.27%
Hydro**	10.68%	7.85%
Nuclear	83.55%	90.86%
AEP SPP	45.10%	43.20%
Coal***	76.87%	77.45%
Super Critical*	83.77%	78.10%
Sub-Critical*	75.02%	77.21%
Gas	23.33%	20.65%
AEP Texas	65.35%	71.95%
Coal****	65.35%	71.95%
AEP System	60.06%	59.54%

Equivalent Availability Factors	2006	2007
AEP East	81.80%	81.09%
Coal	80.29%	78.73%
Super Critical*	80.55%	77.93%
Sub-Critical*	79.49%	81.23%
Gas	92.84%	90.19%
Hydro**	92.30%	86.42%
Nuclear	82.87%	89.68%
AEP SPP	86.25%	84.79%
Coal***	82.87%	82.35%
Super Critical*	86.76%	80.41%
Sub-Critical*	81.67%	83.09%
Gas	88.56%	86.39%
AEP Texas	67.78%	73.95%
Coal****	67.78%	73.95%
AEP System	82.62%	81.84%

Equivalent Forced Outage Rate (EFOR)	2006	2007
AEP East	8.54%	8.32%
Coal	9.37%	9.02%
Super Critical*	8.31%	8.81%
Sub-Critical*	12.63%	9.62%
Gas - See Below		
Hydro**	4.99%	11.61%
Nuclear	0.65%	1.25%
AEP SPP	6.79%	6.75%
Coal***	3.86%	5.49%
Super Critical*	5.50%	6.20%
Sub-Critical*	3.31%	5.23%
Gas	9.73%	8.04%
AEP Texas	23.48%	17.43%
Coal****	23.48%	17.43%
AEP System	8.45%	8.13%

Equivalent Forced Outage Factor (EFOF)	2006	2007
AEP East Gas*****	0.39%	1.23%

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; sub-critical includes coal units with a net maximum capacity less than 450MW.

** Includes all AEP owned Hydro and Pumped Storage generation.

*** CF, EAF, and EFOR do not include Dolet Hills. Dolet Hills included in generation number as owned. Pirkey and Flint Creek reported as owned.

**** Oklaunion reported as owned.

***** East Gas Units evaluated using Equivalent Forced Outage Factor. Since these units are run less frequently, this factor gauges their performance based on Period Hours instead of Service Hours. EFOR uses Service Hours in the denominator, and EFOF uses Period Hours in the denominator.

Net Generation Statistics

Net Generation By Operating Company (in MWhs)

Operating Company	2006	2007
AEP Generating	10,276,134	9,027,362
Appalachian Power	31,494,581	32,588,773
Columbus Southern Power	14,134,232	15,514,495
Indiana Michigan Power	31,950,768	31,604,874
Kentucky Power	7,171,505	7,533,223
Ohio Power	49,341,134	54,155,697
Public Service of Oklahoma	15,139,848	14,439,801
Southwestern Electric Power	19,961,798	19,673,059
Texas Central Company	309,085	41,122
Texas North Company	2,160,348	2,309,566
AEP System Total Net Generation	181,939,433	186,887,972

Notes: Figures represent generation produced from AEP-owned assets only.

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date
AEG	Dresden	Ohio	$309 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B [1]	Coal	Ultra-supercritical	600[1]	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1,110 million in capital investment.
The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

Environmental

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations and the NSR consent decree executed in October 2007.

Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Clean Air Interstate Rule

- Rule finalized March 2005
- Designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- Reductions from 2003-level emissions: ~73% SO_2 & ~61% NO_x
- Reductions occur in phases: Phase I (2009/2010); Phase II (2015)
- Established three cap & trade programs:
  1. Annual SO_2 Trading Program
  2. Annual NO_x Trading Program
  3. Separate Ozone-Season only NO_x Trading Program
- On July 11, 2008 the D. C. Circuit Court issued a decision to remand and vacate CAIR, but the decision is not yet final
- EPA and others have requested rehearing, and the D. C. Circuit Court has requested further briefing on whether any party requested that the rule be vacated, and whether the rule should remain in place while EPA responds to the remand
- A final decision is expected shortly after the briefing is completed (November 2008)

<u>Applicability to AEP</u>

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

Clean Air Visibility Rule

- Rule finalized March 2005
- Designed to address the Clean Air Act's best available retrofit technology (BART) requirements and applicability to plants built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants
- Final rule demonstrates that CAIR will result in more visibility improvements than BART
- States are allowed to substitute CAIR requirements in their 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, additional controls will be required

<u>Applicability to AEP</u>

- Requires SO_2 reductions in Oklahoma and Arkansas
- Scrubbers (FGDs) will be installed at our Northeastern and Flint Creek plants by 2015

Clean Air Mercury Rule

- Rule finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a cap & trade structure to achieve mercury reductions
- On February 8, 2008 the Supreme Court issued a decision to remand and vacate CAMR

AEP will achieve significant mercury reduction as a co-benefit of SCR and FGD systems, but mercury specific control equipment will be needed on several units.

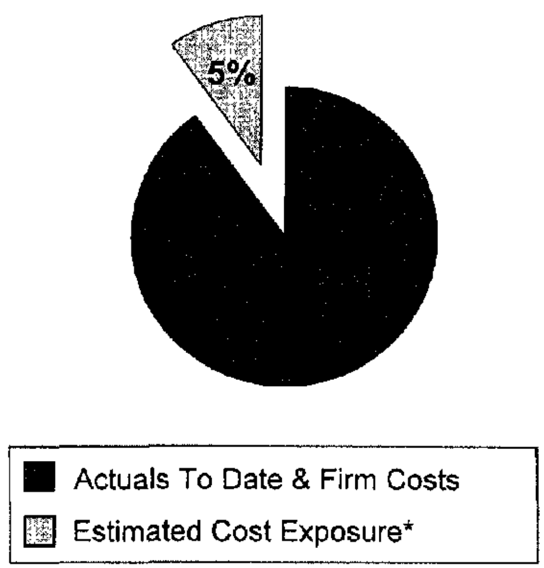
Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2012
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2013
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors - AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $162/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $262/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD retrofit for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.
- Plant modifications increasing unit MW ratings are being implemented as part of the retrofit program
  - For example, Mountaineer turbine valve upgrades will increase unit output by ~30 - 45 MW
  - Similar upgrades will be implemented on other units

Plant modifications will mitigate FGD and SCR capacity consumption.

Emission Limits

In compliance with our 2007 NSR settlement, the following limits are applicable to AEP's eastern generation fleet:

Eastern System-Wide Annual Tonnage Limitations for NO_x	
Calendar Year	Limitation
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016 and each year thereafter	72,000 tons

Eastern System-Wide Annual Tonnage Limitations for SO_2	
Calendar Year	Limitation
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019 and each year thereafter	174,000 tons

Emissions caps do not include any of the gas-fired units, or any new units AEP might build or purchase in the east.

AEP/CertainTeed Gypsum Wallboard Initiative

- CertainTeed Gypsum opened new wallboard manufacturing plant in March of 2008 adjacent to OPCo's Mitchell plant near Moundsville, WV

- Wallboard plant utilizes the gypsum produced from both the Mitchell and Cardinal power plants.

- Gypsum is the by-product of the recently completed FGD (i.e. scrubber) process.

- Key Project Benefits

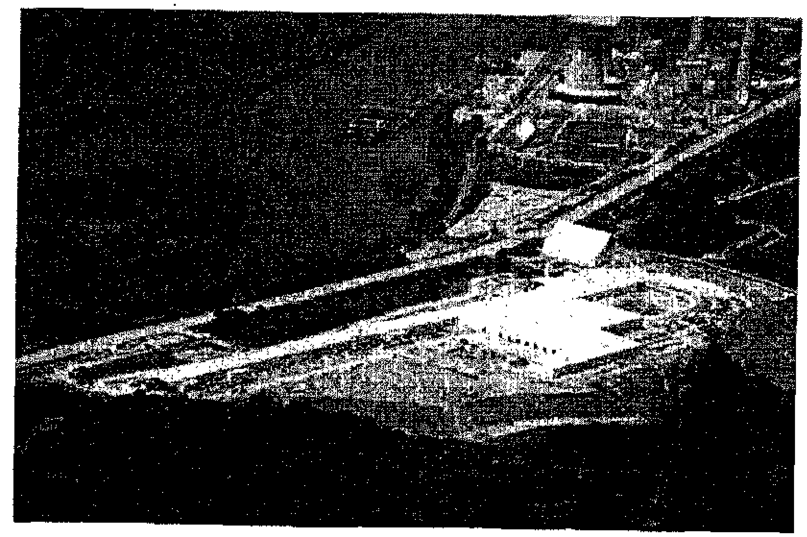
  - Environmental stewardship program which eliminates the need for an expensive gypsum landfill at Mitchell.

  - Significant capital and annual O&M savings for Ohio ratepayers.

  - Wallboard is produced using greater than 96% recycled materials (i.e. gypsum, paper).

  - Created many new good paying jobs.

  - Strong/stable counterparty – CertainTeed is the #1 producer of wallboard in the world



Future Potential Green House Gas Regulations

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - Forestry - 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

New Program Additions

- Incremental Reduction quantity: **5MM tons/yr**
- **Timing: To take effect/receive credits by 2011**
- **Methods**
  - +1000 MWs of Wind PPAs - 2MM tons/yr
  - Domestic Offsets (methane) - 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry - Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets - 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency - 0.2MM tons/yr

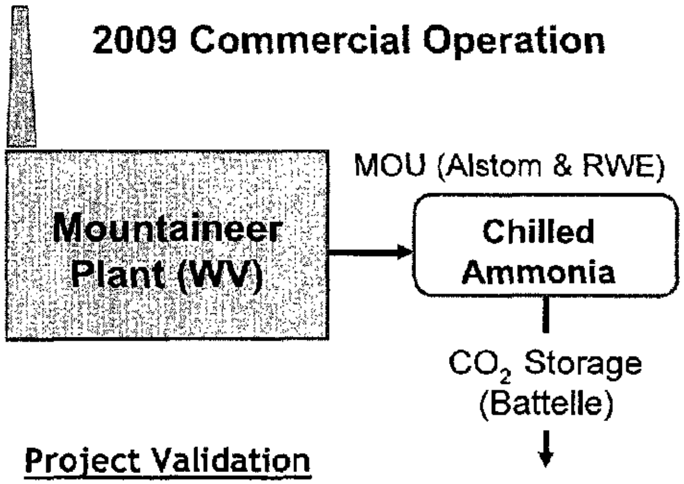
New Technology Additions

- **Commercial solutions for existing fleet**
  - Chilled Ammonia

AEP is committed to a 5mm ton/yr reduction in CO_2 emissions which offsets approx half of the emissions projected from new generation projects previously announced.

Chilled Ammonia Technology Program

2009 Commercial Operation



Project Validation

- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Alstom "Chilled Ammonia" Technology
- Geologic storage for CO_2

Represents Post-Combustion Capture

- Conventional or Advanced Amines; Chilled Ammonia
  - Amine technologies are currently commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine - 25-30%
    - Chilled Ammonia target - 10-15%

Post-combustion carbon solution provides pure CO_2 stream for capture.

Coal

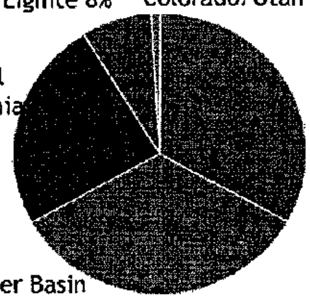
- Coal Procurement, Delivery & Transportation
- Fuel Recovery
- Coal Market Information

Fall EEI 2008

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

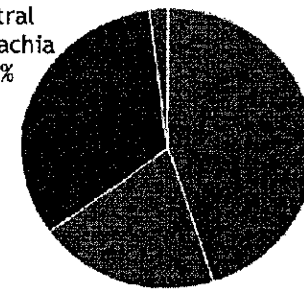
Total AEP System



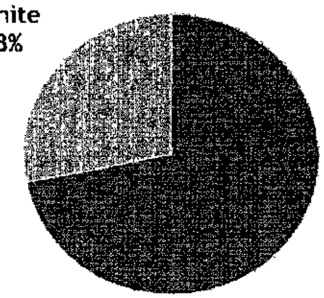
Coal Stats:

- 100% contracted for 2008
- Avg. delivered price - $36.58/ton in 2007
- Approximate 28% price increase in 2008 based on 2007 actual results.

AEP East



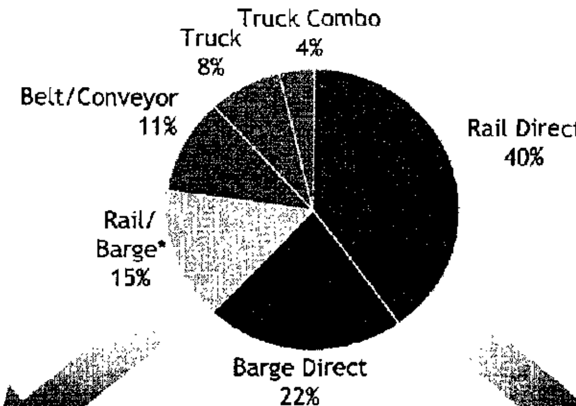
AEP West



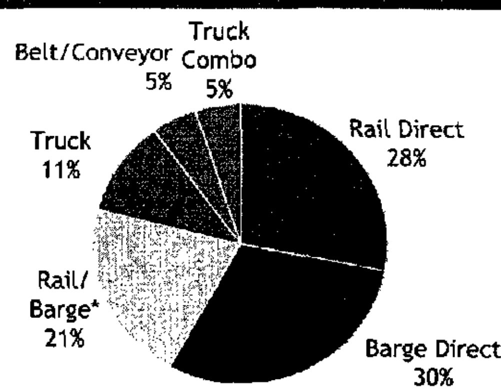
Coal Delivery

2007 Actual

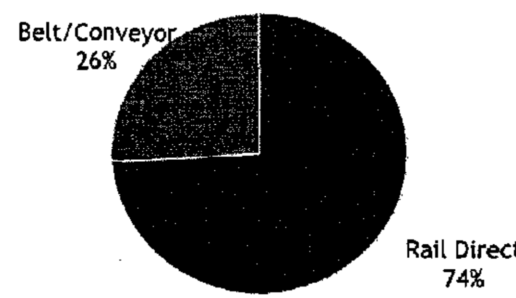
Total AEP System



AEP East



AEP West

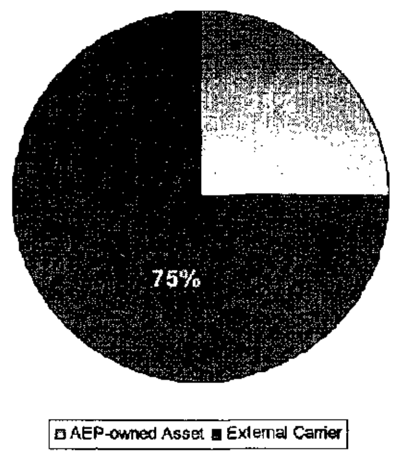


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

2007 Actual

Coal Transportation to AEP Plants*



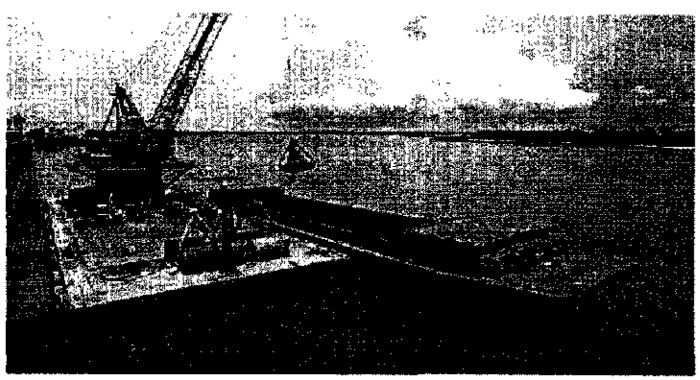
*Represents close approximations

- Current Coal & Transportation Assets:
  - Control over 9,000 railcars
  - Own/lease and operate over 2,900 barges & 80 towboats/tugs
  - Coal handling terminal with 20 million tons of capacity

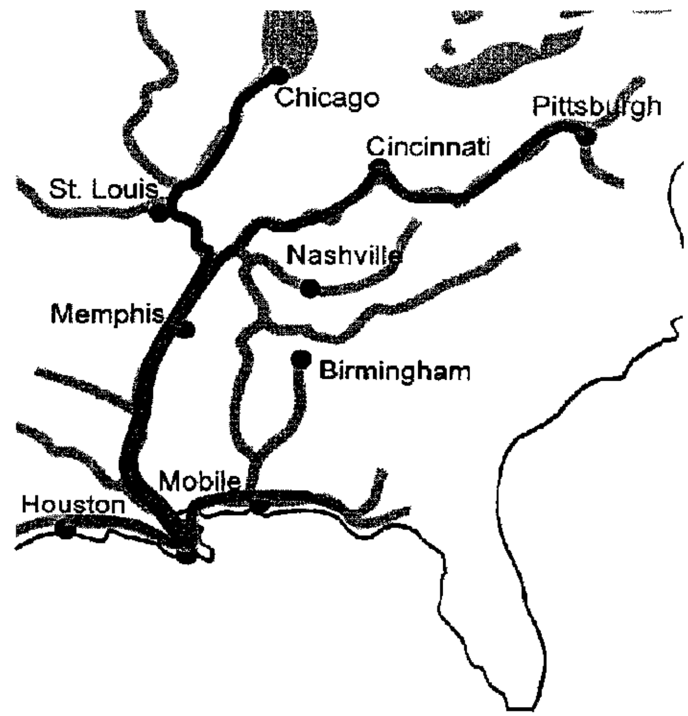
AEP's transportation assets provide flexibility in a constrained delivery environment.

AEP River Operations

- Full-service Inland Waterways carrier
  - ➢ 2,900 hopper barges
  - ➢ 60+ towboats/20 tugs
- Tonnage & Commodity:
  - ➢ Captive: (for AEP)-37MM tons of coal;
  - ➢ Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

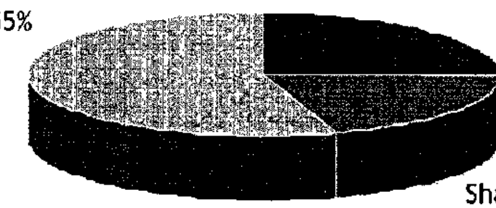


Inland Waterway Routes For AEP River Operations



Fuel Recovery

AEP System



Fuel Cost Recovery (on average)

- In response to Ohio Substitute Senate Bill 221, AEP Ohio filed an Electric Security Plan that would allow recovery of fuel costs from customers who do not switch their supplier. If adopted, AEP's fuel costs will be eligible for recovery in all AEP jurisdictions beginning in 2009.
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

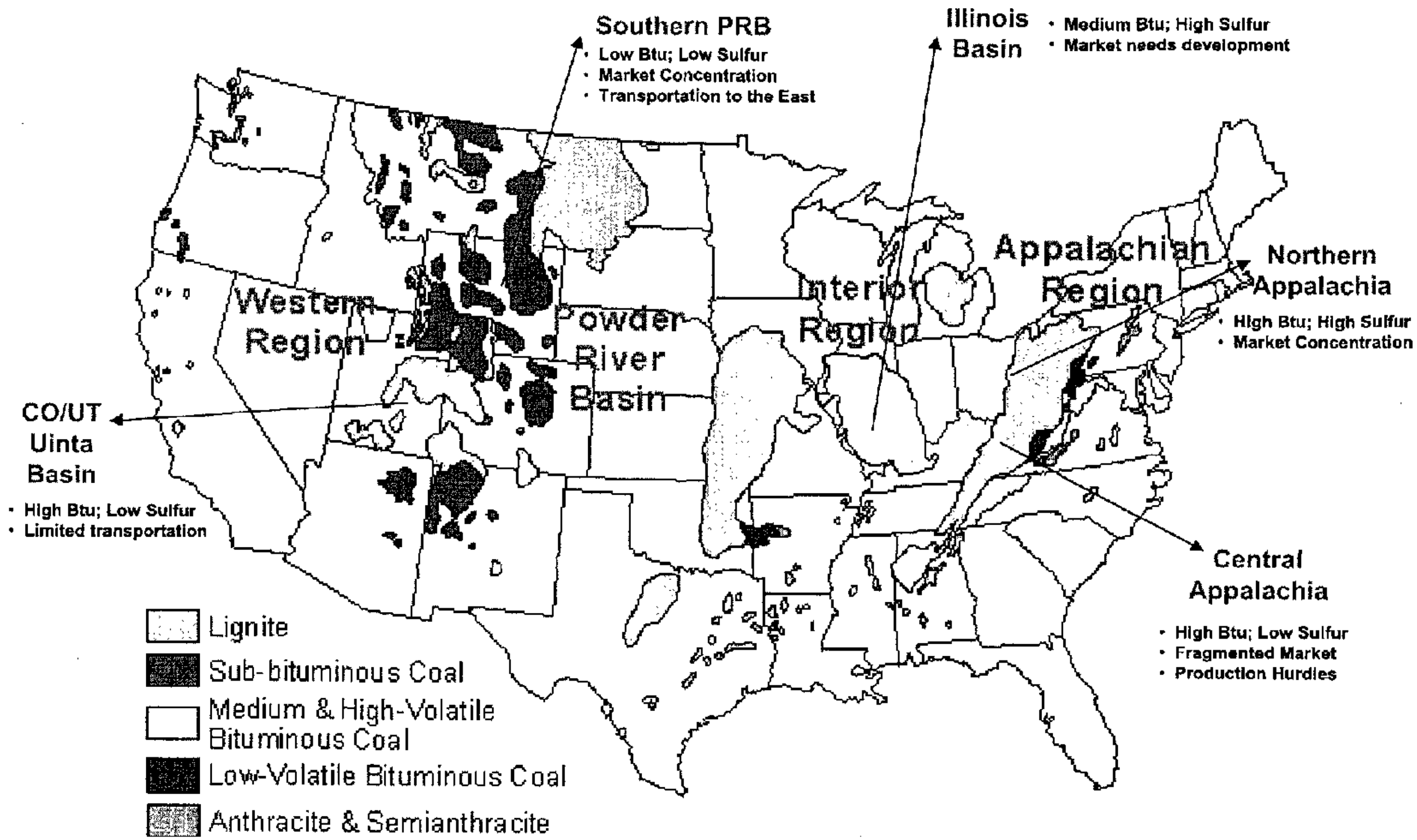
Note: Fuel recovery percentages are based on estimates for 2008 fiscal year

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	Effective 1/1/09	TBD
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Effective January 1, 2009 we have fuel recovery in all jurisdictions.

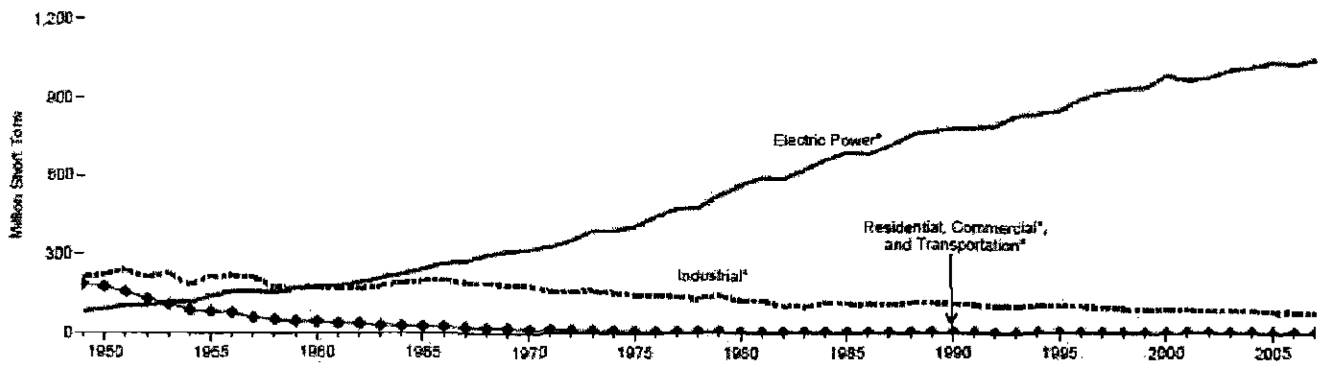
Coal Producing Regions



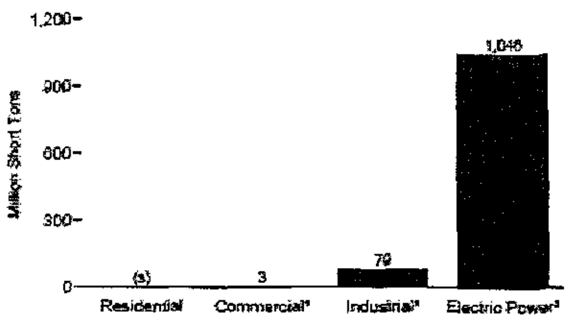
Uses of Coal by Sector

Figure 7.3 Coal Consumption by Sector

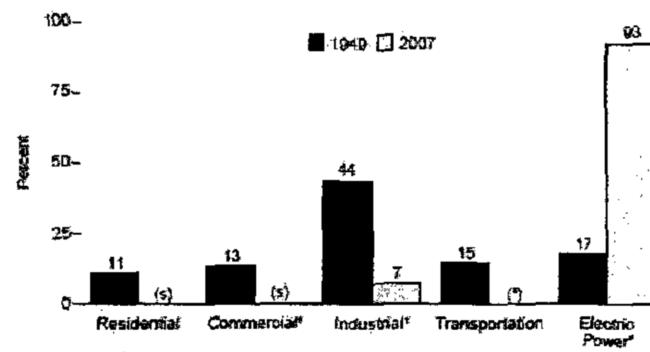
By Sector, 1949-2007



By Sector, 2007



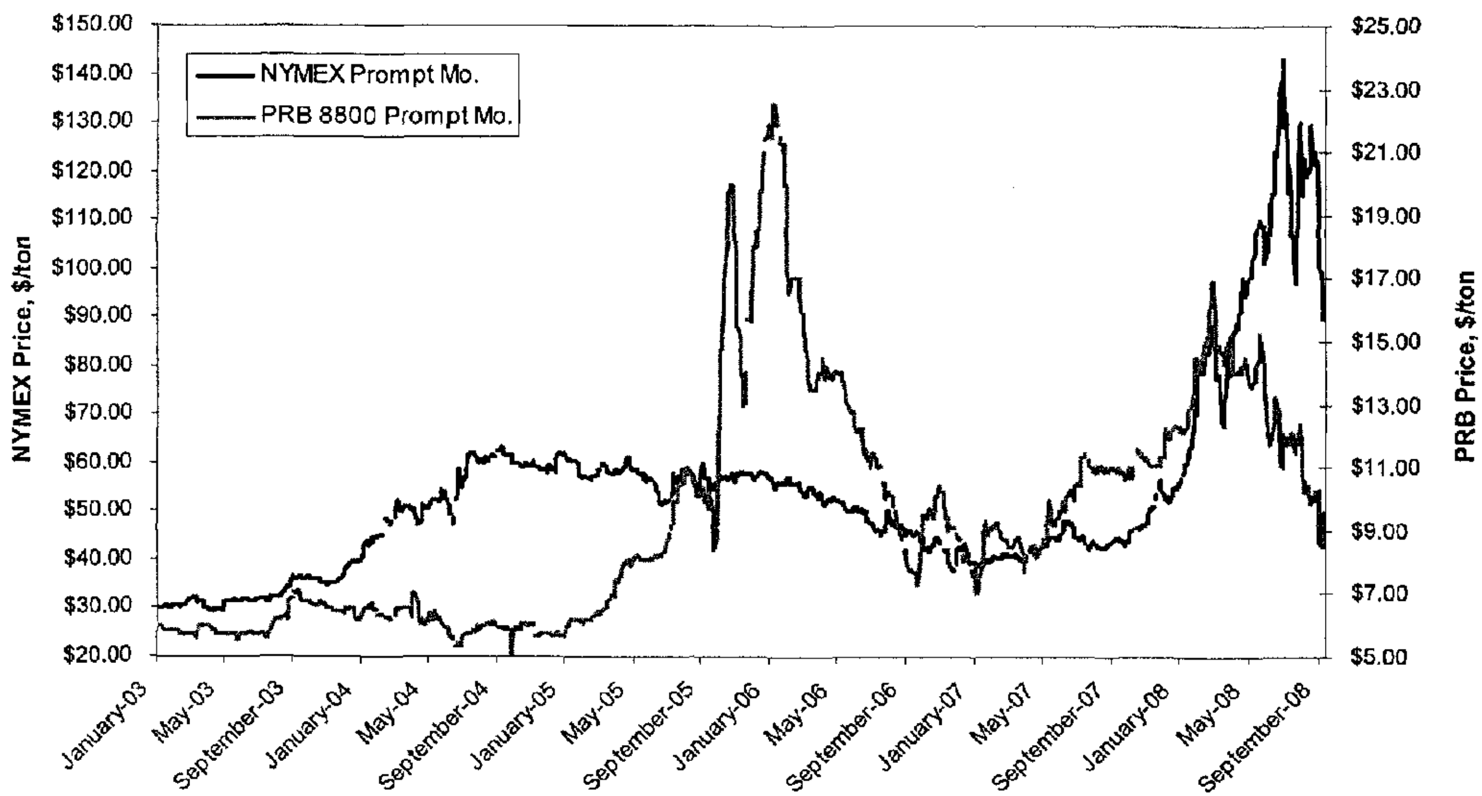
Sector Shares, 1949 and 2007



[1] Includes combined-heat-and-power (CHP) plants and a small number of electricity-only plants.
[2] For 1978 forward, small amounts of transportation sector use are included in "Industrial."

[3] Electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
(s)=Less than 0.5.
Source: Table 7.3.

Domestic Coal Price Markers (FOB Mine)



Domestic Coal Market

Primary drivers for increasing coal prices in the US are:

- Increase in the cost components to produce the product
- Declining productivity due to reserves, safety, etc.
- Declining eastern US coal production....particularly Central Appalachia
- Increasing global demand for coal....particularly Asia
- Inability to bring on new production quickly due to permitting and labor related issues
- High cost to mine in Central Appalachian region
- Capital required for new production
- Sustained pricing, how long?
- Increase in the international demand for US coal products
  - Dramatic increase in east coast and gulf coast US coal exports have lead to much higher priced markets in the US (82M exp; 28M imp)
  - Continued demand of metallurgical coal is drawing steam coal into the metallurgical coal market
  - Weak US Dollar