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, 2008

☐ 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)  1 Riverside Plaza, Columbus, Ohio 43215
Telephone (614) 716-1000
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

Indicate by check mark if the registrants with respect to American Electric Power Company, Inc., Appalachian Power Company and Ohio 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, 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, Ohio Power Company, Public Service Company of Oklahoma or Southwestern Electric 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, Ohio Power Company, Public Service Company of Oklahoma or Southwestern Electric 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, a non-accelerated filer or a smaller reporting company. See definitions of ‘large accelerated filer’, ‘accelerated filer’ and ‘smaller reporting company’ in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)


Large accelerated filer ☑
Non-accelerated filer ☒ (Do not check if a smaller reporting company)

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 and Indiana Michigan Power Company 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:

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

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

<table>
<thead>
<tr>
<th>Registrant</th>
<th>Title of each class</th>
</tr>
</thead>
<tbody>
<tr>
<td>American Electric Power Company, Inc.</td>
<td>None</td>
</tr>
<tr>
<td>Appalachian Power Company</td>
<td>4.50% Cumulative Preferred Stock, Voting, no par value</td>
</tr>
<tr>
<td>Columbus Southern Power Company</td>
<td>None</td>
</tr>
<tr>
<td>Indiana Michigan Power Company</td>
<td>None</td>
</tr>
<tr>
<td>Ohio Power Company</td>
<td>4.50% Cumulative Preferred Stock, Voting, $100 par value</td>
</tr>
<tr>
<td>Public Service Company of Oklahoma</td>
<td>None</td>
</tr>
<tr>
<td>Southwestern Electric Power Company</td>
<td>4.28% Cumulative Preferred Stock, Voting, $100 par value</td>
</tr>
<tr>
<td></td>
<td>4.65% Cumulative Preferred Stock, Voting, $100 par value</td>
</tr>
<tr>
<td></td>
<td>5.00% Cumulative Preferred Stock, Voting, $100 par value</td>
</tr>
<tr>
<td>Company</td>
<td>Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2008, the last trading date of the registrants’ most recently completed second fiscal quarter</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>American Electric Power Company, Inc.</td>
<td>$16,336,246,629</td>
</tr>
<tr>
<td>Appalachian Power Company</td>
<td>None</td>
</tr>
<tr>
<td>Columbus Southern Power Company</td>
<td>None</td>
</tr>
<tr>
<td>Indiana Michigan Power Company</td>
<td>None</td>
</tr>
<tr>
<td>Ohio Power Company</td>
<td>None</td>
</tr>
<tr>
<td>Public Service Company of Oklahoma</td>
<td>None</td>
</tr>
<tr>
<td>Southwestern Electric Power Company</td>
<td>None</td>
</tr>
</tbody>
</table>

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

## Documents Incorporated By Reference

<table>
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<tr>
<th>Description</th>
<th>Part of Form 10-K Into Which Document Is Incorporated</th>
</tr>
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<tbody>
<tr>
<td>Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2008:</td>
<td>Part II</td>
</tr>
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<td>American Electric Power Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>Appalachian Power Company</td>
<td></td>
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<tr>
<td>Columbus Southern Power Company</td>
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<tr>
<td>Indiana Michigan Power Company</td>
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<tr>
<td>Ohio Power Company</td>
<td></td>
</tr>
<tr>
<td>Public Service Company of Oklahoma</td>
<td></td>
</tr>
<tr>
<td>Southwestern Electric Power Company</td>
<td></td>
</tr>
<tr>
<td>Portions of Information Statements of the following companies for 2009 Annual Meeting of Shareholders:</td>
<td>Part III</td>
</tr>
<tr>
<td>Appalachian Power Company</td>
<td></td>
</tr>
<tr>
<td>Ohio Power Company</td>
<td></td>
</tr>
<tr>
<td>Public Service Company of Oklahoma</td>
<td></td>
</tr>
<tr>
<td>Southwestern Electric Power Company</td>
<td></td>
</tr>
</tbody>
</table>

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.
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## Glossary of Terms

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

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<th>Definition</th>
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</thead>
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<td>AECC</td>
<td>Arkansas Electric Cooperative Corporation</td>
</tr>
<tr>
<td>AEGCo</td>
<td>AEP Generating Company, an electric utility subsidiary of AEP</td>
</tr>
<tr>
<td>AEP or parent</td>
<td>American Electric Power Company, Inc.</td>
</tr>
<tr>
<td>AEP East companies</td>
<td>APCo, CSPCo, I&amp;M, KPCo and OPCo</td>
</tr>
<tr>
<td>AEP Power Pool</td>
<td>APCo, CSPCo, I&amp;M, KPCo and OPCo, as parties to the Interconnection Agreement</td>
</tr>
<tr>
<td>AEP River Operations</td>
<td>AEP’s inland river transportation subsidiary, AEP River Operations LLC (formerly AEP MEMCO LLC), operating primarily on the Ohio, Illinois, and lower Mississippi rivers</td>
</tr>
<tr>
<td>AEPSC</td>
<td>American Electric Power Service Corporation, a service company subsidiary of AEP</td>
</tr>
<tr>
<td>AEP System or the System</td>
<td>The American Electric Power System, an integrated electric utility system, owned and operated by AEP’s electric utility subsidiaries</td>
</tr>
<tr>
<td>AEP West companies</td>
<td>PSO, SWEPCo, TCC and TNC</td>
</tr>
<tr>
<td>AEP Utilities</td>
<td>AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation</td>
</tr>
<tr>
<td>AFUDC</td>
<td>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)</td>
</tr>
<tr>
<td>ALJ</td>
<td>Administrative law judge</td>
</tr>
<tr>
<td>APCo</td>
<td>Appalachian Power Company, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>APSC</td>
<td>Arkansas Public Service Commission</td>
</tr>
<tr>
<td>Buckeye</td>
<td>Buckeye Power, Inc., an unaffiliated corporation</td>
</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act</td>
</tr>
<tr>
<td>CAAA</td>
<td>Clean Air Act Amendments of 1990</td>
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<td>CERCLA</td>
<td>Comprehensive Environmental Response, Compensation and Liability Act of 1980</td>
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<td>CO2</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>Cook Plant</td>
<td>The Donald C. Cook Nuclear Plant (2,143 MW), owned by I&amp;M, and located near Bridgman, Michigan</td>
</tr>
<tr>
<td>CSPCo</td>
<td>Columbus Southern Power Company, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>CSW</td>
<td>Central and South West Corporation, a public utility holding company that merged with AEP in June 2000.</td>
</tr>
<tr>
<td>CSW Operating Agreement</td>
<td>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.</td>
</tr>
<tr>
<td>DOE</td>
<td>United States Department of Energy</td>
</tr>
<tr>
<td>Dow</td>
<td>The Dow Chemical Company, and its affiliates collectively, unaffiliated companies</td>
</tr>
<tr>
<td>DP&amp;L</td>
<td>The Dayton Power and Light Company, an unaffiliated utility company</td>
</tr>
<tr>
<td>Duke Carolina</td>
<td>Duke Energy Carolinas, LLC</td>
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<tr>
<td>Duke Indiana</td>
<td>Duke Energy Indiana, Inc.</td>
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<td>Duke Ohio</td>
<td>Duke Energy Ohio, Inc.</td>
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<td>EMF</td>
<td>Electric and Magnetic Fields</td>
</tr>
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<td>EPA</td>
<td>United States Environmental Protection Agency</td>
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<tr>
<td>EPACT</td>
<td>The Energy Policy Act of 2005</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
</tr>
<tr>
<td>ESP</td>
<td>Electric Security Plans, filed with the PUO, pursuant to the Ohio Amendments</td>
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<td>ETEC</td>
<td>East Texas Electric Cooperative</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<tr>
<td>Fitch</td>
<td>Fitch Ratings, Inc.</td>
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<tr>
<td>FPA</td>
<td>Federal Power Act</td>
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<tr>
<td>I&amp;M</td>
<td>Indiana Michigan Power Company, a public utility subsidiary of AEP</td>
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<tr>
<td>IGCC</td>
<td>Integrated Gasification Combined Cycle</td>
</tr>
<tr>
<td>Abbreviation or Acronym</td>
<td>Definition</td>
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<tr>
<td>-------------------------</td>
<td>------------</td>
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<tr>
<td>Interconnection Agreement</td>
<td>Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&amp;M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants</td>
</tr>
<tr>
<td>IURC</td>
<td>Indiana Utility Regulatory Commission</td>
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<tr>
<td>KPCo</td>
<td>Kentucky Power Company, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>KPSC</td>
<td>Kentucky Public Service Commission</td>
</tr>
<tr>
<td>Lawrenceburg Plant</td>
<td>A 1,146 MW gas-fired unit owned by AEGCo and located near Lawrenceburg, Indiana</td>
</tr>
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<td>LLWPA</td>
<td>Low-Level Waste Policy Act of 1980</td>
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<td>LPSC</td>
<td>Louisiana Public Service Commission</td>
</tr>
<tr>
<td>MISO</td>
<td>Midwest Independent Transmission System Operator</td>
</tr>
<tr>
<td>Moody’s</td>
<td>Moody’s Investors Service, Inc.</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>NOx</td>
<td>Nitrogen oxide</td>
</tr>
<tr>
<td>NPC</td>
<td>National Power Cooperatives, Inc., an unaffiliated corporation</td>
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<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
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<td>OASIS</td>
<td>Open Access Same-time Information System</td>
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<td>OCC</td>
<td>Corporation Commission of the State of Oklahoma</td>
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<td>Ohio Act</td>
<td>Ohio electric restructuring legislation</td>
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<tr>
<td>Ohio Amendments</td>
<td>Amendments to the Ohio Act adopted in April 2008 which require electric utilities to adjust their rates by filing an ESP with the PUCO</td>
</tr>
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<td>OPCo</td>
<td>Ohio Power Company, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>OVEC</td>
<td>Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 43.47% equity interest</td>
</tr>
<tr>
<td>PJM</td>
<td>PJM Interconnection, L.L.C., a regional transmission organization</td>
</tr>
<tr>
<td>PSO</td>
<td>Public Service Company of Oklahoma, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>PUCO</td>
<td>Public Utilities Commission of Ohio</td>
</tr>
<tr>
<td>PUCT</td>
<td>Public Utility Commission of Texas</td>
</tr>
<tr>
<td>RCRA</td>
<td>Resource Conservation and Recovery Act of 1976, as amended</td>
</tr>
<tr>
<td>REP</td>
<td>Texas retail electricity provider</td>
</tr>
<tr>
<td>Rockport Plant</td>
<td>A generating plant owned and partly leased by AEGCo and I&amp;M (two 1,300 MW, coal-fired) located near Rockport, Indiana</td>
</tr>
<tr>
<td>ROE</td>
<td>Return on Equity</td>
</tr>
<tr>
<td>RTO</td>
<td>Regional Transmission Organization</td>
</tr>
<tr>
<td>SEC</td>
<td>Securities and Exchange Commission</td>
</tr>
<tr>
<td>S&amp;P</td>
<td>Standard &amp; Poor’s Ratings Service</td>
</tr>
<tr>
<td>SO2</td>
<td>Sulfur dioxide</td>
</tr>
<tr>
<td>SPP</td>
<td>Southwest Power Pool</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Southwestern Electric Power Company, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>TCA</td>
<td>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</td>
</tr>
<tr>
<td>TCC</td>
<td>AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP</td>
</tr>
<tr>
<td>TEA</td>
<td>Transmission Equalization Agreement dated April 1, 1984 by and among APCo, CSPCo, I&amp;M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets</td>
</tr>
<tr>
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<td>Texas electric restructuring legislation</td>
</tr>
</tbody>
</table>
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:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- 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 including our ability to restore Cook Plant Unit 1 in a timely manner.
- 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 and transmission line facilities (including our ability to obtain any necessary regulatory or siting approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) 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.
- 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 implementation of the recently passed utility law in Ohio and the allocation of costs within RTOs, including PJM and SPP.
- 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 and the impact on future funding requirements.
• 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. Virginia has returned to integrated regulated rates.

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, 2008, the subsidiaries of AEP had a total of 21,912 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 962,000 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, 2008, APCo and its wholly owned subsidiaries had 2,575 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 749,000 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, 2008, CSPCo had 1,323 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 582,000 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, 2008, I&M had 2,879 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, 2008, KPCo had 480 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, 2008, Kingsport Power Company had 58 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 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, 2008, OPCo had 2,434 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 527,000 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, 2008, PSO had 1,279 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 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 471,000 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, 2008, SWEPCo had 1,641 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 761,000 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, 2008, TCC had 1,201 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 185,000 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 an agreement effective through 2027. At December 31, 2008, TNC had 370 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, 2008, WPCo had 62 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, 2008, AEPSC had 6,351 employees.
## CLASSES OF SERVICE

The principal classes of service from which AEP and the registrant subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2008 are as follows:

<table>
<thead>
<tr>
<th>Description</th>
<th>AEP System(a)</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>UTILITY OPERATIONS:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Retail Sales</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential Sales</td>
<td>$4,267,000</td>
<td>$891,159</td>
<td>$720,761</td>
<td>$427,877</td>
</tr>
<tr>
<td>Commercial Sales</td>
<td>3,116,000</td>
<td>426,277</td>
<td>684,277</td>
<td>333,575</td>
</tr>
<tr>
<td>Industrial Sales</td>
<td>2,954,000</td>
<td>601,166</td>
<td>328,010</td>
<td>364,670</td>
</tr>
<tr>
<td>PJM Net Charges</td>
<td>(214,000)</td>
<td>(72,898)</td>
<td>(40,249)</td>
<td>(38,782)</td>
</tr>
<tr>
<td>Provision for Rate Refund</td>
<td>(105,000)</td>
<td>(52,910)</td>
<td>(30,359)</td>
<td>(33,279)</td>
</tr>
<tr>
<td>Other Retail Sales</td>
<td>210,000</td>
<td>55,359</td>
<td>5,873</td>
<td>6,044</td>
</tr>
<tr>
<td><strong>Total Retail</strong></td>
<td>$10,228,000</td>
<td>1,848,153</td>
<td>1,668,313</td>
<td>1,060,105</td>
</tr>
<tr>
<td>Wholesale</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Off-System Sales</td>
<td>2,690,000</td>
<td>720,574</td>
<td>430,093</td>
<td>675,205</td>
</tr>
<tr>
<td>Transmission</td>
<td>58,000</td>
<td>(52,740)</td>
<td>(30,419)</td>
<td>(16,235)</td>
</tr>
<tr>
<td><strong>Total Wholesale</strong></td>
<td>$2,748,000</td>
<td>667,834</td>
<td>399,674</td>
<td>658,970</td>
</tr>
<tr>
<td>Other Electric Revenues</td>
<td>244,000</td>
<td>26,235</td>
<td>11,623</td>
<td>8,694</td>
</tr>
<tr>
<td>Other Operating Revenues</td>
<td>106,000</td>
<td>18,199</td>
<td>5,542</td>
<td>19,102</td>
</tr>
<tr>
<td>Sales To Affiliates</td>
<td>-</td>
<td>328,735</td>
<td>122,949</td>
<td>419,488</td>
</tr>
<tr>
<td><strong>Total Utility Operating Revenues</strong></td>
<td>$13,326,000</td>
<td>2,889,156</td>
<td>2,208,101</td>
<td>2,166,359</td>
</tr>
<tr>
<td><strong>OTHER</strong></td>
<td>1,114,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>TOTAL REVENUES</strong></td>
<td>$14,440,000</td>
<td>$ 2,889,156</td>
<td>$ 2,208,101</td>
<td>$2,166,359</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>UTILITY OPERATIONS:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Retail Sales</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential Sales</td>
<td>$ 602,770</td>
<td>$ 557,195</td>
<td>$440,826</td>
</tr>
<tr>
<td>Commercial Sales</td>
<td>402,149</td>
<td>407,052</td>
<td>382,984</td>
</tr>
<tr>
<td>Industrial Sales</td>
<td>694,890</td>
<td>357,884</td>
<td>280,082</td>
</tr>
<tr>
<td>PJM Net Charges</td>
<td>(47,705)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Provision for Rate Refund</td>
<td>(42,435)</td>
<td>13,811</td>
<td>21,417</td>
</tr>
<tr>
<td>Other Retail Sales</td>
<td>9,439</td>
<td>99,158</td>
<td>7,906</td>
</tr>
<tr>
<td><strong>Total Retail</strong></td>
<td>1,619,108</td>
<td>1,435,100</td>
<td>1,133,215</td>
</tr>
<tr>
<td>Wholesale</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Off-System Sales</td>
<td>511,961</td>
<td>62,980</td>
<td>267,689</td>
</tr>
<tr>
<td>Transmission</td>
<td>(38,529)</td>
<td>27,234</td>
<td>39,966</td>
</tr>
<tr>
<td><strong>Total Wholesale</strong></td>
<td>473,432</td>
<td>90,214</td>
<td>307,655</td>
</tr>
<tr>
<td>Other Electric Revenues</td>
<td>24,257</td>
<td>24,176</td>
<td>17,157</td>
</tr>
<tr>
<td>Other Operating Revenues</td>
<td>18,937</td>
<td>4,853</td>
<td>45,893</td>
</tr>
<tr>
<td>Sales to Affiliates</td>
<td>961,200</td>
<td>101,602</td>
<td>50,842</td>
</tr>
<tr>
<td><strong>Total Utility Operating Revenues</strong></td>
<td>3,096,934</td>
<td>1,655,945</td>
<td>1,554,762</td>
</tr>
<tr>
<td><strong>OTHER</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>TOTAL REVENUES</strong></td>
<td>$ 3,096,934</td>
<td>$ 1,655,945</td>
<td>$1,554,762</td>
</tr>
</tbody>
</table>

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated for the year ended December 31, 2008.
**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, borrowing under AEP’s revolving credit agreements 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. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2008 Annual Reports, under the heading entitled *Financial Condition* for additional information concerning short-term funding and our access to bank lines of credit, commercial paper and capital markets.

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, 2008, 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 of AEP would be considered an immediate termination event. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2008 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**

The credit ratings of AEP and its registrant subsidiaries as of February 18, 2009 are set forth below. Over the first two months of 2009, Moody’s placed the senior unsecured debt rating of AEP on negative outlook, the senior unsecured debt rating of OPCo, SWEPCo, TCC and TNC on review for possible downgrade and changed the outlook of APCo from negative to stable. In February 2008 Fitch downgraded the senior unsecured debt rating of PSO to BBB+ with stable outlook. Fitch placed the senior unsecured debt rating of APCo and TCC on negative outlook in May 2008 and February 2009, respectively. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2008 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants.

<table>
<thead>
<tr>
<th>Company</th>
<th>Moody’s Senior Unsecured</th>
<th>Moody’s Outlook*</th>
<th>S&amp;P Senior Unsecured</th>
<th>S&amp;P Outlook*</th>
<th>Fitch Senior Unsecured</th>
<th>Fitch Outlook*</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>Baa2</td>
<td>N</td>
<td>BBB</td>
<td>S</td>
<td>BBB</td>
<td>S</td>
</tr>
<tr>
<td>APCo</td>
<td>P2</td>
<td>S</td>
<td>A2</td>
<td>S</td>
<td>F2</td>
<td>S</td>
</tr>
<tr>
<td>APCo Short Term Rating</td>
<td>Baa2</td>
<td>S</td>
<td>BBB</td>
<td>S</td>
<td>BBB+</td>
<td>N</td>
</tr>
<tr>
<td>CSPCo</td>
<td>A3</td>
<td>S</td>
<td>BBB</td>
<td>S</td>
<td>A-</td>
<td>S</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>Baa2</td>
<td>S</td>
<td>BBB</td>
<td>S</td>
<td>BBB</td>
<td>S</td>
</tr>
<tr>
<td>OPCo</td>
<td>A3</td>
<td>R</td>
<td>BBB</td>
<td>S</td>
<td>BBB+</td>
<td>S</td>
</tr>
<tr>
<td>PSO</td>
<td>Baa1</td>
<td>S</td>
<td>BBB</td>
<td>S</td>
<td>BBB+</td>
<td>S</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Baa1</td>
<td>R</td>
<td>BBB</td>
<td>S</td>
<td>BBB+</td>
<td>S</td>
</tr>
</tbody>
</table>

* S=Stable Outlook; N=Negative Outlook; R=Under Review for Possible Downgrade
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 and regulatory responses to it, including limitations on CO₂ emissions. See Management’s Financial Discussion and Analysis of Results of Operations under the headings entitled Environmental Matters – Potential Regulation of CO₂ and Other 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/or 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 Litigation - Environmental Litigation and Note 6 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2008 Annual Reports, for further information.

• Rules issued by the EPA and certain states that require substantial reductions in SO₂ and NOₓ emissions and future rules for mercury emission reductions, 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 2008 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 2008 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, and regulates systems that withdraw surface water for use in our power plants. See Management’s Financial Discussion and Analysis of Results of Operations, included in the 2008 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, and other laws governing the use of ash impoundments, including containment dams. 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 2008 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, 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. 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 2008 Annual Reports, for more information regarding environmental matters.

Environmental Investments

Investments related to improving AEP System plants’ environmental performance and compliance with air and water quality standards during 2006, 2007 and 2008 and the current estimates for 2009, 2010 and 2011 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 CO₂ 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 2008 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total AEP System*</td>
<td>$1,366,200</td>
<td>$994,100</td>
<td>$886,800</td>
<td>$436,100</td>
<td>$581,900</td>
<td>$892,400</td>
</tr>
<tr>
<td>APCo</td>
<td>532,800</td>
<td>351,900</td>
<td>361,200</td>
<td>99,400</td>
<td>183,900</td>
<td>71,400</td>
</tr>
<tr>
<td>CSPCo</td>
<td>138,900</td>
<td>130,000</td>
<td>162,800</td>
<td>69,700</td>
<td>54,600</td>
<td>57,900</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>23,200</td>
<td>9,300</td>
<td>22,400</td>
<td>40,600</td>
<td>3,600</td>
<td>2,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>600,800</td>
<td>481,700</td>
<td>311,800</td>
<td>179,800</td>
<td>49,200</td>
<td>116,400</td>
</tr>
<tr>
<td>PSO</td>
<td>500</td>
<td>1,500</td>
<td>5,000</td>
<td>1,000</td>
<td>22,200</td>
<td>265,100</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>21,000</td>
<td>14,300</td>
<td>12,000</td>
<td>22,300</td>
<td>170,400</td>
<td>243,600</td>
</tr>
</tbody>
</table>

* Includes expenditures of the subsidiaries shown 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 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, 2008, the member-load-ratios were as follows:

<table>
<thead>
<tr>
<th></th>
<th>Peak Demand (MW)</th>
<th>Member-Load Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>7,848</td>
<td>33.2</td>
</tr>
<tr>
<td>CSPCo</td>
<td>4,406</td>
<td>18.6</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>4,264</td>
<td>18.0</td>
</tr>
<tr>
<td>KPCo</td>
<td>1,678</td>
<td>7.1</td>
</tr>
<tr>
<td>OPCo</td>
<td>5,458</td>
<td>23.1</td>
</tr>
</tbody>
</table>

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 remained functionally separated through December 31, 2008 as authorized by their rate stabilization plans approved by the PUCO. Pursuant to rules recently adopted by the PUCO, CSPCo and OPCo expect to file corporate separation plans with the PUCO. See Note 4 to the consolidated financial statements, entitled Rate Matters, included in the 2008 Annual Reports, for more information.

APCo, CSPCo, I&M, KPCo and OPCo are 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, 2006, 2007 and 2008:
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 as of May 1, 2006, 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, 2006, 2007 and 2008:

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$319,500</td>
<td>$454,800</td>
<td>$575,300</td>
</tr>
<tr>
<td>CSPCo</td>
<td>281,700</td>
<td>173,000</td>
<td>233,200</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(146,100)</td>
<td>(93,200)</td>
<td>(153,000)</td>
</tr>
<tr>
<td>KPCo</td>
<td>38,800</td>
<td>41,200</td>
<td>65,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>(493,900)</td>
<td>(575,800)</td>
<td>(720,500)</td>
</tr>
</tbody>
</table>

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 its 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 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. In an order issued November 26, 2008, the FERC ruled that AEP should reallocate pre-tax trading margins from off-system sales between the AEP East Companies and the AEP West Companies during the period from June 2000 to March 2006 governed by the previous system integration agreement. See Note 4 to the
consolidated financial statements, entitled *Rate Matters*, included in the 2008 Annual Reports under the heading entitled *FERC Rate Matters* for additional information.

**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 and in adjacent regions. 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 offsets 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, 2008, counterparties have posted approximately $29 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 $100 million with counterparties and exchanges). Since open trading contracts are valued based on market power prices, exposures change daily. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2008 Annual Reports, under the heading entitled *Quantitative and Qualitative Disclosures About Risk Management Activities* for additional information.

**Fuel Supply**

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

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal and Lignite</td>
<td>85%</td>
<td>85%</td>
<td>86%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>6%</td>
<td>6%</td>
<td>6%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>9%</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>Hydroelectric and other</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
</tr>
</tbody>
</table>

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 has been increasing due to increased mining costs (including labor, diesel fuel, mining equipment, implementation of new safety regulations, and permitting difficulties) in addition to higher international demand for eastern U.S. coals. To the extent practical, management has responded to increases in the price of coal by rebalancing the coal used in its generating facilities with products from different coal regions and sources 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 9,000 railcars, 726 barges, 18 towboats and a coal handling terminal with 18 million tons of annual capacity to move and store coal for use in our generating facilities. See AEP River 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 price of coal in the various spot markets remains volatile. During the first half of 2008, spot market prices for coal generally rose; in the second half of 2008, spot market prices for coal generally decreased. Most of the coal we purchase is procured through long-term contracts. The prices we pay under these contracts is usually lower than the spot market price of coal. As these long-term contracts expire they are replaced with new agreements, often at higher prices. The price we paid for coal in 2008 rose from the prior year as a result of this. We expect this trend to continue in 2009.
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 AEP System companies:

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total coal delivered to AEP System plants (thousands of tons)</td>
<td>76,045</td>
<td>72,644</td>
<td>77,054</td>
</tr>
<tr>
<td>Average price per ton of purchased coal</td>
<td>$35.27</td>
<td>$36.65</td>
<td>$47.14</td>
</tr>
</tbody>
</table>

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, availability of acceptable coals, labor issues and weather conditions which may interrupt production or deliveries. At December 31, 2008, the System’s coal inventory was approximately 32 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, AEP has developed programs to conserve coal supplies at its plants. Such programs have been filed and reviewed with federally approved electric reliability organizations. 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 nearly 103 billion cubic feet of natural gas during 2008 for generating power. This represents a slight decrease from 2007 due to reduced demand in AEP’s eastern jurisdictions. Many of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. 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, as needed.

**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 continues to lease a portion of its nuclear fuel requirements.

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. Initial loading of spent nuclear fuel into the dry casks is tentatively scheduled to begin in 2011, which should permit normal operations through 2037, its current licensing period.

**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, 2008, the total decommissioning trust fund balance for the Cook Plant was $959 million. The balance of funds available to decommission Cook Plant will differ based on contributions.
and investment returns. 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 9 to the consolidated financial statements, entitled Nuclear, included in the 2008 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 Utah licenses a low-level radioactive waste disposal sites which currently accepts low-level radioactive waste from Michigan. I&M’s access to the Barnwell, South Carolina facility ended in 2008. With some modifications to existing facilities, I&M will have capacity for onsite storage of that waste previously 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), and 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 authorized environmental investments related to their ownership interests. As of December 2008, OVEC’s Board of Directors has authorized capital expenditures totaling $981.6 million in connection with the engineering and construction of flue gas desulfurization (sulfur dioxide scrubber) projects and the associated scrubber waste disposal landfills at its two generating plants. OVEC’s Board of Directors has delayed for at least eighteen months final completion of construction on one of the plants. If approved and fully funded, the estimated total cost to complete the scrubber and landfill projects would be in excess of $1.2 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 approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See Item 1—Utility Operations - 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 Agreement**: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system in AEP East transmission zone 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, 2008 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, 2006, 2007 and 2008:

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td>$(16,000)</td>
<td>$(25,000)</td>
<td>$(29,000)</td>
</tr>
<tr>
<td>CSPCo</td>
<td>46,000</td>
<td>51,900</td>
<td>55,000</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(37,000)</td>
<td>(34,600)</td>
<td>(37,000)</td>
</tr>
<tr>
<td>KPCo</td>
<td>(2,000)</td>
<td>(800)</td>
<td>(2,000)</td>
</tr>
<tr>
<td>OPCo</td>
<td>9,000</td>
<td>8,500</td>
<td>13,000</td>
</tr>
</tbody>
</table>

**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 in the AEP West transmission zone, 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 pursuant to the SPP OATT and ERCOT protocols as described above during the years ended December 31, 2006, 2007 and 2008:

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>$1,800</td>
<td>$500</td>
<td>$8,200</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>(1,900)</td>
<td>(500)</td>
<td>(8,200)</td>
</tr>
<tr>
<td>TCC</td>
<td>1,100</td>
<td>1,100</td>
<td>1,500</td>
</tr>
<tr>
<td>TNC</td>
<td>(1,000)</td>
<td>(1,100)</td>
<td>(1,500)</td>
</tr>
</tbody>
</table>

**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 – Electric Transmission and Distribution - 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 2008 Annual Reports under the heading entitled *Regional Transmission Rate Proceedings at the FERC* for additional information regarding 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 cost-based 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 with respect to wholesale power and transmission service transactions as well as certain unbundled retail transmission rates mainly in Ohio. 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 adjusted 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.

Public utilities have traditionally financed capital investments until the new asset was placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives are leading the dialogue with our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, securitization, formula rates and the inclusion of future test-year projections into rates.
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 only. 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, CSPCo and OPCo did not have a fuel adjustment clause to recover increased fuel costs in Ohio through 2008. CSPCo and OPCo are seeking to implement a fuel cost recovery mechanism.

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. See Note 4 to the consolidated financial statements, entitled Rate Matters, included in the 2008 Annual Reports, for more information regarding pending rate matters.

**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. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

**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. Pursuant to rate stabilization plans approved by the PUCO, CSPCo and OPCo provide retail generation service at rates approved by the PUCO. CSPCo and OPCo are providing and will continue to provide distribution services to retail customers at cost-based rates approved by the PUCO. Transmission services will continue to be provided at OATT rates based on rates established by the FERC. CSPCo and OPCo’s generation/supply rates are no longer cost-based regulated. Pursuant to the Ohio Amendments, CSPCo and OPCo have filed their ESP with PUCO, each requesting an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. CSPCo and OPCo have not had a fuel adjustment clause since 1999.

**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.

**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 an agreement effective through 2027. 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 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 on a cost of service basis.

**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 a fuel adjustment clause factor with a true-up to actual.

**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 through an expanded net energy clause which trues up to actual expenses.

**Other Jurisdictions**: The public utility subsidiaries of AEP also provide service at cost based regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan. These jurisdictions provide for the timely recovery of fuel costs through fuel adjustment clauses that true-up to actual expenses.
The following table illustrates the current rate regulation status of the states in which the public utility subsidiaries of AEP operate:

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>Status of Base Rates for Power Supply</th>
<th>Energy Delivery</th>
<th>Status</th>
<th>Off-System Sales Profits Shared with Ratepayers</th>
<th>Percentage of AEP System Retail Revenues(2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ohio</td>
<td>See footnote 3</td>
<td>See footnote 3</td>
<td>See footnote 3</td>
<td>Not applicable</td>
<td>32%</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes</td>
<td>14%</td>
</tr>
<tr>
<td>Texas ERCOT</td>
<td>Not applicable (4)</td>
<td>Not applicable</td>
<td>Not applicable</td>
<td>Not applicable</td>
<td>8%</td>
</tr>
<tr>
<td>Texas SPP</td>
<td>Not capped or frozen (4)</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes</td>
<td>4%</td>
</tr>
<tr>
<td>West Virginia</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes</td>
<td>10%</td>
</tr>
<tr>
<td>Indiana</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>No</td>
<td>9%</td>
</tr>
<tr>
<td>Virginia</td>
<td>Not capped or frozen (5)</td>
<td>Not capped or frozen (5)</td>
<td>Active</td>
<td>Yes</td>
<td>9%</td>
</tr>
<tr>
<td>Louisiana</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes, above base levels</td>
<td>4%</td>
</tr>
<tr>
<td>Kentucky</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes, above and below base levels(6)</td>
<td>4%</td>
</tr>
<tr>
<td>Arkansas</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes, above base levels</td>
<td>3%</td>
</tr>
<tr>
<td>Michigan</td>
<td>Not capped or frozen</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Yes, in some areas</td>
<td>2%</td>
</tr>
<tr>
<td>Tennessee</td>
<td>See footnote 7</td>
<td>Not capped or frozen</td>
<td>Active</td>
<td>Not applicable</td>
<td>1%</td>
</tr>
</tbody>
</table>

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

(2) 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, 2008.

(3) The PUCO approved rate stabilization plans (RSP) filed by CSPCo and OPCo that began after the market development period and extended through December 31, 2008 during which OPCo’s retail generation rates increased 7% annually and CSPCo’s retail generation rates increased 3% annually. Distribution rates were frozen, with certain exceptions, through December 31, 2008. Pursuant to the Ohio Amendments, in July 2008, CSPCo and OPCo filed ESP with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo have requested retroactive application of the new rates, including the fuel cost recovery mechanism,
back to January 1, 2009 upon approval of the ESP. In December 2008, the PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO issues a ruling on the ESP or the end of the February 2009 billing cycle, whichever comes first. In January 2009, CSPCo and OPCo filed an application with the PUCO requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. See Note 4 to the consolidated financial statements, entitled Rate Matters.

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

(5) Rates in Virginia were capped, subject to adjustment, through 2008. Beginning January 1, 2009, rates are neither capped nor frozen.

(6) If the monthly off-system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo for a portion of the shortfall. If the monthly off-system sales profits exceed the monthly base amount built into base rates, KPCo reimburses ratepayers for a portion of the excess.

(7) Prior to January 1, 2009, base rates for power supply were not capped or frozen. Effective January 1, 2009, base rates for power supply will phase-in increases of $24 million, $3 million and $9 million for the years beginning January 1, 2009, 2010 and 2011, respectively. Any filing to increase the amount Kingsport pays for the non-fuel component of its purchase power, other than as discussed above, cannot be made prior to January 1, 2012.

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, directly or through an RTO, 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, directly or through an RTO, 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’ transmission employees from providing non-public transmission information to the utility’s marketing employees.

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, including OASIS and tariff responsibilities, to one or more RTOs. As a result, 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 ended in 2009 for residential customers (except those seeking green power) pursuant to a new law 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 cost-based distribution rates are approved by the PUCO and whose cost-based transmission rates are based on rates established by the FERC. 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 2008 Annual Reports, for a discussion of the impact of restructuring on distribution rates. The PUCO has authorized CSPCo and OPCo to remain functionally separated.

Pursuant to the Ohio Amendments, CSPCo and OPCo have filed ESP with the PUCO, each requesting an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. See Note 4 to the consolidated financial statements, entitled Rate Matters, included in the 2008 Annual Reports, for more information.

Texas Restructuring

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 also 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 at non-cost based rates for generation/supply of electricity. 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 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.
TCC elected to sell its generating facilities to establish its recoverable stranded costs. 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. 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 2008 Annual Reports.

**Michigan Customer Choice**

Customer choice commenced for I&M’s Michigan customers on January 1, 2002. In October 2008, the Governor of Michigan signed legislation to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year. Rates for retail electric service for I&M’s Michigan customers were unbundled (though they continue to be cost based regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2008, 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 adjusted 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 APCo’s fuel adjustment clause factor 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 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.

**AEP RIVER OPERATIONS**

Our AEP River 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 permit AEP utility subsidiary affiliates to use certain of our equipment at rates that reflect our cost. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generating plants. We charge affiliated customers rates that reflect our costs. AEP River Operations includes approximately 2,252 barges, 42 towboats and 22 harbor boats that we own or lease. These assets are separate from the barges and towboats dedicated exclusively to transporting coal for use as fuel in our own generating facilities discussed under the prior segment. See Item 1 – Utility Operations - Electric Generation —Fuel Supply—Coal and Lignite.

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 and marketing business. We enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in the ERCOT market. As of December 31, 2008, the assets utilized in this segment included approximately 310 MW of company-owned domestic wind power facilities, 75MW of domestic wind power from a long-term purchase power agreement and 377 MW of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers TNC’s interest in the Oklaunion power station to AEP Energy Partners, Inc. During first quarter of 2009, one of our non-utility affiliates, AEP Energy Partners, Inc., entered into a purchase power agreement effective through 2029 that entitles us to the output of a wind farm of approximately 100MW capacity. TNC’s transfer of coal-fired generation capacity is in order to comply with the separation requirements of the Texas Act. The power obtained from the Oklaunion power station is 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

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 was settled in August, 2005. 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 7 to the consolidated financial statements entitled Acquisitions, Dispositions, Discontinued Operations and Impairments.

For information regarding other non-core investments, see Note 7 to the consolidated financial statements entitled Acquisitions, Dispositions, Discontinued Operations and Impairments, included in the 2008 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. Most 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 in its entirety. (Applies to AEP and I&M.)**

In January 2008, I&M filed a request to increase base rates in its Indiana jurisdiction by approximately $80 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.

**Our request for rate recovery in Ohio may not be approved in its entirety. (Applies to AEP, OPCo and CSPCo)**

In July 2008, within the parameters of the ESP, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism that primarily includes fuel costs, purchased power costs including renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. Management expects a PUCO decision on the ESP filings in the first quarter of 2009. CSPCo and OPCo have requested retroactive application of the new rates back to January 1, 2009 upon approval. If the PUCO denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

**We may not recover costs incurred to begin constructing 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 is canceled 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, if we have recorded any construction work or investments as a regulatory asset we may need to impair that asset in the event the project is canceled.

**Rate regulation may delay or deny full recovery of capital improvements, additions and other 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. Traditionally, we have financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Long lead times in construction, the high costs of plant and equipment and difficult capital markets has heightened the risks involved in...
our capital investments and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, securitization, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, 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.

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

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including:

- major facility or equipment failure;
- an environmental event such as a serious spill or release;
- fires, floods, droughts, earthquakes, hurricanes or other natural disasters;
- wars, terrorist acts or threats and other catastrophic events;
- significant health impairments or disease events, and;
- other serious operational problems.

**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 2,191 MW, or 8-9% of the electricity we generate. 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 unsettled $108 million of unsettled gross SECA revenues. AEP has settled $112 million of SECA revenues for $10 million. We have recorded a provision for estimated settlement refunds. After completed and in-process settlements, the AEP East companies have a remaining reserve balance of $34 million to settle the remaining $108 million in unsettled gross SECA revenues. Based on this settlement history, the $34 million reserve balance should be adequate to absorb the potential refund of the remaining contested SECA rates, assuming that the claims are settled. Payments in excess of the reserve balance could harm our results of operations and financial position.

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, KPSC, VSCC and WVPSC. The adjudication of the filing with the IURC is pending. 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.

At times, demand for power could exceed our supply capacity. \textit{(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. This would increase the pressure on our short-term debt financing capacity in times of tight liquidity. We may not always have the ability to pass these costs on to our customers, and the time lag between incurring costs and recovery can be long. 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

\textbf{If we are unable to access capital markets on reasonable terms, it could have an adverse impact on our net income, cash flows and financial condition. \textit{(Applies to each registrant)}}

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. The recent volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse impact on net income, cash flows and financial condition.

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

The credit ratings agencies periodically review 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. In the current period of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our costs of capital 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. Over the first two months of 2009, Moody’s placed the senior unsecured debt rating of AEP on negative outlook, the senior unsecured debt rating of OPCo, SWEPCo, TCC and TNC on review for possible downgrade and changed the outlook of APCo from negative to stable. In February 2008 Fitch downgraded the senior unsecured debt rating of PSO to BBB+ with stable outlook. Fitch placed the senior unsecured debt rating of APCo and TCC on negative outlook in May 2008 and February 2009, respectively.
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.

**Our retirement plans may require additional significant contributions.** *(Applies to each registrant.)*

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under our defined benefit pension plans. The recent deterioration of the capital markets has led to a decline in the market value of these assets and a reduction in the benchmark discount rate with respect to a return on these assets. Accordingly, we expect that our future funding requirements of the obligations under our defined benefit plans to significantly increase.

**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. AEP indebtedness and common stock dividends are effectively subordinated to all subsidiary indebtedness and preferred stock obligations.

**Our operating results may fluctuate on a seasonal or quarterly basis and with general economic conditions.** *(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. Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions. For example, a leading customer of APCO, Century Aluminum in West Virginia, announced in February 2009 that it was ceasing operations.

**Failure to attract and retain an appropriately qualified workforce could harm our results of operations.** *(Applies to each registrant.)*

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and
expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

**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 and the costs of transport 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 exposed to changes in the price and availability of coal and the price and availability to transport 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 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. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants.

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.

**Risks Relating to State Restructuring**

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 2008, TCC’s largest customer accounted for 28% of its operating revenues; TNC’s largest customer (a non-utility affiliate) accounted for 28% of its operating revenues and its second largest customer accounted for 12% 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. Approximately 90% of the electricity generated by the AEP system is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. 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 CO₂ emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO₂ emission reductions, none have advanced through the legislature. In April 2007 the U.S. Supreme Court determined that CO₂ is an “air pollutant” and that the Federal EPA has authority to regulate CO₂ emissions under the CAA. In July 2008 the Federal EPA issued an advance notice of proposed rulemaking (ANPR) that requests comments on a wide variety of issues in response to the U.S. Supreme Court’s decision. The ANPR could lead to regulations limiting the emissions of CO₂ from our generating plants. In addition, the Obama administration has indicated that it intends to focus on reducing CO₂ emissions.

Costs of compliance with environmental regulations could adversely affect our net income 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 CO₂ 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, without such recovery those costs could adversely affect future net income 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 CO₂ 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 CO₂ 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 financial performance may be impaired if Cook Plant Unit 1 is not returned to service in a reasonable period of time or in a cost-efficient manner.** *(Applies to AEP and I&M)*

Cook Plant Unit 1 is a 1,055 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. I&M is working with its insurance company and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair and replacement of the turbine rotors is estimated to cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. If any of these costs are not covered by warranty, insurance or recovered through the regulatory process, or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.
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, the rate of return on our capital investments is not determined 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 can 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

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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, 2008, the AEP System owned (or leased where indicated) generating plants with net power capabilities (winter rating) shown in the following table:

<table>
<thead>
<tr>
<th>Company</th>
<th>Stations</th>
<th>Coal MW</th>
<th>Gas MW</th>
<th>Natural Nuclear MW</th>
<th>Lignite MW</th>
<th>Hydro MW</th>
<th>Oil MW</th>
<th>Total MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEGCo</td>
<td>2 (a)</td>
<td>1,310</td>
<td>1,146</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2,456</td>
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<tr>
<td>APCo</td>
<td>17 (b)(c)</td>
<td>5,093</td>
<td>516</td>
<td></td>
<td>681</td>
<td></td>
<td></td>
<td>6,290</td>
</tr>
<tr>
<td>CSPCo</td>
<td>7 (d)</td>
<td>2,341</td>
<td>1,357</td>
<td></td>
<td>3</td>
<td></td>
<td></td>
<td>3,701</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>9 (a)</td>
<td>2,305</td>
<td>2,191</td>
<td></td>
<td>15</td>
<td></td>
<td></td>
<td>4,511</td>
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<tr>
<td>KPCo</td>
<td>1</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,060</td>
</tr>
<tr>
<td>OPCo</td>
<td>8 (b)(c)(e)</td>
<td>8,452</td>
<td>452</td>
<td></td>
<td>26</td>
<td></td>
<td></td>
<td>8,478</td>
</tr>
<tr>
<td>PSO</td>
<td>8 (f)(g)</td>
<td>1,026</td>
<td>3,552</td>
<td></td>
<td>25</td>
<td></td>
<td></td>
<td>4,603</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>10 (h)</td>
<td>1,848</td>
<td>2,152</td>
<td>850</td>
<td></td>
<td></td>
<td>4,850</td>
<td></td>
</tr>
<tr>
<td>TNC</td>
<td>6 (i)(j)</td>
<td>377</td>
<td>262</td>
<td></td>
<td></td>
<td></td>
<td>8</td>
<td>647</td>
</tr>
</tbody>
</table>

System Totals | 62 | 23,812 | 8,985 | 2,191 | 850 | 722 | 36 | 36,596 |
Percentage of System Totals | 65.1 | 24.5 | 6.0 | 2.3 | 2.0 | 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.

(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.

(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, 2008, 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 and TNC’s ownership interest is reflected in this portion of the table.

(g) PSO began commercial operation of Units 4 and 5, of 85 MW each (winter rating), at its gas-fired Southwestern Plant in February 2008. Also, commercial operation of PSO’s Units 3 and 4, of 85 MW each (winter rating), at the gas-fired Riverside Plant began in April 2008.

(h) SWEPCo owns generating units in common with Cleco Corporation and other unaffiliated parties. Only its ownership interest is reflected in this table.
(i) TNC sold the four inactive plants of Fort Phantom, Lake Pauline, San Angelo, and Rio Pecos to Eagle Construction and Environmental Services, LP for a total of 667 MW (winter rating) in February 2008. A fifth inactive plant owned by TNC, the Oak Creek Plant (85 MW, winter rating), was conveyed to the City of Sweetwater under terms related to a settlement agreement executed by the parties in 2005.

(j) 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.

<table>
<thead>
<tr>
<th>Cook Plant</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Unit 1</td>
<td>Unit 2</td>
</tr>
<tr>
<td>Year Placed in Operation</td>
<td>1975</td>
<td>1978</td>
</tr>
<tr>
<td>Year of Expiration of NRC License</td>
<td>2034</td>
<td>2037</td>
</tr>
<tr>
<td>Nominal Net Electrical Rating in Kilowatts</td>
<td>1,084,000</td>
<td>1,107,000</td>
</tr>
<tr>
<td>Net Capacity Factors (a)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>59.2%(b)</td>
<td>96.6%</td>
</tr>
<tr>
<td>2007</td>
<td>97.4%</td>
<td>83.8%</td>
</tr>
<tr>
<td>2006</td>
<td>80.4%</td>
<td>86.5%</td>
</tr>
<tr>
<td>2005</td>
<td>88.8%</td>
<td>97.1%</td>
</tr>
</tbody>
</table>

(a) Net Capacity Factor values for Unit 1 in 2007 and 2008 reflect Nominal Net Electrical Rating in Kilowatts of 1,084,000. The Net Capacity Factor values for Unit 1 in 2005 and 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.

(b) Unit 1 Net Capacity Factor for 2008 was impacted by a forced outage caused by low pressure turbine blade failures.

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. 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.
**GENERATION AND MARKETING**

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities. Information concerning these facilities at December 31, 2008 is listed below.

<table>
<thead>
<tr>
<th>Facility</th>
<th>Fuel</th>
<th>Location</th>
<th>Capacity Total MW</th>
<th>Ownership Interest</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Desert Sky Wind Farm</td>
<td>Wind</td>
<td>Texas</td>
<td>161</td>
<td>100%</td>
<td>Exempt Wholesale Generator(a)</td>
</tr>
<tr>
<td>Trent Wind Farm</td>
<td>Wind</td>
<td>Texas</td>
<td>150</td>
<td>100%</td>
<td>Exempt Wholesale Generator(a)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>311</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) As defined under rules issued pursuant to EPACT.

See Note 7 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations and Impairments*, included in the 2008 Annual Reports, for a discussion of AEP’s disposition of independent power producer and foreign generation assets.

**TRANSMISSION AND DISTRIBUTION FACILITIES**

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

<table>
<thead>
<tr>
<th></th>
<th>Total Overhead Circuit Miles of Transmission and Distribution Lines</th>
<th>Circuit Miles of 765kV Lines</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP System (a)</td>
<td>224,095 (b)</td>
<td>2,116</td>
</tr>
<tr>
<td>APCo</td>
<td>52,022</td>
<td>734</td>
</tr>
<tr>
<td>CSPCo (a)</td>
<td>15,519</td>
<td>—</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>22,023</td>
<td>615</td>
</tr>
<tr>
<td>Kingsport Power Company</td>
<td>1,358</td>
<td>—</td>
</tr>
<tr>
<td>KPCo</td>
<td>11,020</td>
<td>258</td>
</tr>
<tr>
<td>OPCo</td>
<td>30,762</td>
<td>509</td>
</tr>
<tr>
<td>PSO</td>
<td>21,193</td>
<td>—</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>21,453</td>
<td>—</td>
</tr>
<tr>
<td>TCC</td>
<td>29,564</td>
<td>—</td>
</tr>
<tr>
<td>TNC</td>
<td>17,476</td>
<td>—</td>
</tr>
<tr>
<td>WPCo</td>
<td>1,705</td>
<td>—</td>
</tr>
</tbody>
</table>

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of overhead transmission lines not identified with an operating company.

**TITLES**

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

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia, and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes, and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years. See Management’s Financial Discussion and Analysis of Results of Operations included in the 2008 Annual Reports, for more information on current siting proceedings.

CONSTRUCTION PROGRAM

GENERAL

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. AEP forecasts $2.6 billion of construction expenditures, excluding AFUDC, for 2009, which is a significant reduction from the original 2009 capital forecast set in 2008. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital. Due to recent credit market instability, we reviewed our projections for capital expenditures for 2009 and 2010. We identified reductions of approximately $750 million for 2009. We are evaluating possible additional capital reductions for 2010.

PROPOSED TRANSMISSION FACILITIES

Joint Venture in PJM

In June 2007, PJM authorized the construction of a major new transmission line to address the reliability and efficiency needs of the PJM system. The line would be 765kV and would run approximately 275 miles from APCo’s Amos substation in West Virginia to Allegheny Energy Inc.’s (“AYE”) proposed Kemptown station in north central Maryland. In September 2007, AEP and AYE entered into a joint venture to construct, own and operate transmission facilities in the PJM region, including the Amos-to-Kemptown transmission line. In December 2007, the joint venture filed an application with the FERC for approval of a return on equity and formula rate for the Amos-to-Kemptown transmission line. FERC approval of the settlement among the participants is pending. In addition to the rate recovery sought through the FERC, the joint venture will seek appropriate regulatory approvals from the appropriate state utility commissions for siting and Certificates of Public Convenience and Necessity. The total cost of the Amos-to-Kemptown line is estimated to be approximately $1.8 billion, and AEP’s estimated share will be approximately $600 million. The joint venture is not consolidated with AEP for financial or tax reporting purposes. See Management’s Financial Discussion and Analysis of Results of Operations included in the 2008 Annual Reports for more information.
**Joint Venture in ERCOT**

In January 2007, TCC entered into an agreement to establish a joint venture with MidAmerican Energy Holdings Company ("MidAmerican") to fund, own and operate electric transmission assets in ERCOT. In January 2007, a filing was made with the PUCT seeking regulatory approval to operate as an electric transmission utility in Texas, to transfer transmission assets from TCC to the joint venture and to establish a wholesale transmission tariff. In December 2007, the PUCT issued an order authorizing the transaction, the initial tariffs and a certificate of convenience and necessity to operate in the ERCOT region. A Texas district court reversed the PUCT’s order granting a certificate of convenience. Both the PUCT and ETT have appealed this decision. The PUCT’s appeal suspends enforceability of the court’s judgment pending final appellate review. Subsidiaries of AEP and MidAmerican each hold a 50 percent equity interest in the joint venture. The joint venture is not consolidated with AEP for financial or tax reporting purposes. See Management’s Financial Discussion and Analysis of Results of Operations, Note 4 and Note 7 to the consolidated financial statements, entitled *Rate Matter and Acquisitions, Dispositions, Discontinued Operations and Impairments*, respectively, included in the 2008 Annual Reports, for more information.

**PROPOSED GENERATION FACILITIES**

*SWEPCo Projects*

In 2008, SWEPCo began construction of a 508 MW combined-cycle natural gas fired plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana (the “Stall Unit”). PUCT and LPSC have approved construction of the Stall Unit and filing has been made with the APSC seeking approval to construct the Stall Unit. The Stall Unit is estimated to cost $384 million, excluding AFUDC, and is expected to be operational in mid-2010. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2008 Annual Reports, for more information.

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named the John W. Turk, Jr. Power Plant (the “Turk Plant”). In 2008, SWEPCo received various regulatory approvals, including the issuance of an air permit from the Arkansas Department of Environmental Quality, to construct the Turk Plant and actual construction commenced in November 2008. SWEPCo anticipates owning 73% of the Turk Plant and will be the operator. During 2007, SWEPCO signed joint ownership, construction and operations agreements with Oklahoma Municipal Power Authority, AECC and ETEC for the remaining 27% of the Turk Plant. ETEC’s participation in the Turk Plant is contingent on obtaining certain regulatory approvals that are pending. The Turk Plant is estimated to cost $1.6 billion with SWEPCo’s 73% portion estimated to cost $1.2 billion, excluding AFUDC. The Turk Plant is expected to be operational in 2013. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2008 Annual Reports, for more information.

*Ohio IGCC Plant*

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. In June 2006, the PUCO issued an order approving a tariff to recover pre-construction costs, subject to refund. In March 2008, the Ohio Supreme Court remanded the matter back to the PUCO after review. Pending the outcome of the remand, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. In December 2007 we estimated that its construction would cost $2.7 billion. Since then costs to construct generation facilities have continued to increase significantly. Management continues to pursue the ultimate construction of the IGCC plant. However, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists. See Management’s Financial Discussion and Analysis of Results of Operations and Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2008 Annual Reports, for more information.
West Virginia IGCC

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity (CCN) to construct a proposed 629 MW IGCC plant. The plant is to be built adjacent to APCo’s existing Mountaineer Generating Station in Mason County, WV for an estimated cost of $2.2 billion. In March 2008, the WVPSC granted APCo the CCN to build the plant and approved the requested cost recovery. In July 2007, APCo filed a request with the VSCC for a rate adjustment clause to recover initial costs associated with a proposed IGCC plant. The VSCC issued an order in April 2008 denying APCo’s requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. See Management’s Financial Discussion and Analysis of Results of Operations and Note 4 to the consolidated financial statements, entitled Rate Matters, included in the 2008 Annual Reports, for more information.

Mountaineer Carbon Capture Project

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a 20 MW CO2 capture demonstration facility at APCo’s Mountaineer 1320 MW generating unit. APCo and Alstom will each own part of the CO2 capture facility. APCo will also construct and own the necessary facilities to store the CO2. RWE AG, a German electric power and natural gas public utility, is participating in the evaluation of the commercial and technical feasibility of taking captured CO2 from the flue gas stream and storing it in deep geologic formations. APCo’s estimated cost for its share of the facilities is $76 million. Through December 31, 2008, APCo incurred $29 million in capitalized project costs that are included in regulatory assets. APCo is earning a return on the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the VSCC in November 2008. See Note 4 to the consolidated financial statements, entitled Rate Matters, included in the 2008 Annual Reports, for more information.

Other

Our significant planned environmental investments in emission control installations at existing coal-fired plants and our commitment to IGCC and ultra-supercritical technology reinforce our belief that coal will be a lower-emission domestic energy source of the future and further signals our commitment to invest in clean, environmentally safe technology. For additional information regarding anticipated environmental expenditures, see Management’s Financial Discussion and Analysis of Results of Operations under the heading entitled Environmental Matters.

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2006, 2007 and 2008 and a current estimate of 2009 construction expenditures, in each case excluding AFUDC, capitalized interest and assets acquired under leases.

<table>
<thead>
<tr>
<th></th>
<th>2006 Actual (b)</th>
<th>2007 Actual (c)</th>
<th>2008 Actual (d)</th>
<th>2009 Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total AEP System (a)</td>
<td>$3,551,000</td>
<td>$3,414,000</td>
<td>$3,981,200</td>
<td>$2,584,000</td>
</tr>
<tr>
<td>APCo</td>
<td>922,700</td>
<td>715,700</td>
<td>755,800</td>
<td>367,500</td>
</tr>
<tr>
<td>CSPCo</td>
<td>325,000</td>
<td>330,800</td>
<td>435,700</td>
<td>269,600</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>306,900</td>
<td>282,400</td>
<td>372,400</td>
<td>361,600</td>
</tr>
<tr>
<td>OPCo</td>
<td>978,600</td>
<td>806,000</td>
<td>675,200</td>
<td>439,400</td>
</tr>
<tr>
<td>PSO</td>
<td>245,200</td>
<td>302,600</td>
<td>274,200</td>
<td>187,700</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>339,400</td>
<td>516,800</td>
<td>689,300</td>
<td>457,400</td>
</tr>
</tbody>
</table>
(a) Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.
(b) Excludes Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $3,528,000).
(c) Excludes $512 million for the purchase of Lawrenceburg, Dresden (AEGCo) and Darby (CSPCo) and Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $3,556,000).
(d) Excludes Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $3,799,600).

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System’s construction program. Due to recent credit market instability, we reviewed our projections for capital expenditures for 2009 and 2010. We identified reductions of approximately $750 million for 2009. We are evaluating possible additional capital reductions for 2010.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to our generating plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see Note 9 to the consolidated financial statements entitled Nuclear for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 6 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, incorporated by reference in Item 8.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

AEP, APCo, OPCo, PSO and SWEPCo. None.

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).
EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of February 1, 2009.

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Office (a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Michael G. Morris</td>
<td>62</td>
<td>Chairman of the Board, President and Chief Executive Officer</td>
</tr>
<tr>
<td>Nicholas K. Akins</td>
<td>48</td>
<td>Executive Vice President</td>
</tr>
<tr>
<td>Carl L. English</td>
<td>62</td>
<td>Chief Operating Officer</td>
</tr>
<tr>
<td>John B. Keane</td>
<td>62</td>
<td>Executive Vice President, General Counsel and Secretary</td>
</tr>
<tr>
<td>Holly Keller Koeppel</td>
<td>50</td>
<td>Executive Vice President and Chief Financial Officer</td>
</tr>
<tr>
<td>Venita McCellon-Allen</td>
<td>49</td>
<td>Executive Vice President</td>
</tr>
<tr>
<td>Richard E. Munczinski</td>
<td>56</td>
<td>Senior Vice President</td>
</tr>
<tr>
<td>Robert P. Powers</td>
<td>54</td>
<td>President-AEP Utilities</td>
</tr>
<tr>
<td>Brian X. Tierney</td>
<td>41</td>
<td>Executive Vice President</td>
</tr>
<tr>
<td>Susan Tomasky</td>
<td>55</td>
<td>President – AEP Transmission</td>
</tr>
</tbody>
</table>

(a) Messrs. Morris, Akins, Munczinski, Powers and Tierney and Ms. Koeppel and Ms. Tomasky have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Messrs. Akins, Munczinski, Powers and Tierney, Ms. Koeppel and Ms. Tomasky became executive officers of AEP effective with their promotions on August 15, 2006, June 1, 2008, October 24, 2001, January 1, 2008, November 18, 2002 and January 26, 2000, respectively. Mr. Keane became an executive officer of AEP in July 2004. Before joining AEPSC in July 2004, Mr. Keane was President of Bainbridge Crossing Advisors. Mr. English became an executive officer of AEP on August 1, 2004. Before joining AEPSC in August 2004, Mr. English was President and Chief Executive Officer of Consumers Energy gas division. Ms. McCellon-Allen became an executive officer of AEP in July 2008. From August 2006 to June 2008, Ms. McCellon-Allen was President and Chief Operating Officer of SWEPCO. Before joining AEPSC in 2004, Ms. McCellon-Allen was SVP-Human Resources for Baylor Heath Care Systems. All of the above officers are appointed annually for a one-year term by the board of directors of AEP.

APCo, OPCo, PSO and SWEPCo. The names of the executive officers of APCo, OPCo, PSO and SWEPCo, the positions they hold with these companies, their ages as of February 1, 2009, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, OPCo, PSO and SWEPCo are elected annually to serve a one-year term.

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Position</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Michael G. Morris (a)(b)</td>
<td>62</td>
<td>Chairman of the Board, President, Chief Executive Officer, and Director of AEP</td>
<td>2004-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Chairman of the Board, Chief Executive Officer and Director of APCo, OPCo, PSO and SWEPCo</td>
<td>2004-Present</td>
</tr>
<tr>
<td>Nicholas K. Akins (a)</td>
<td>48</td>
<td>Executive Vice President, Vice President and Director of APCo, OPCo, PSO and SWEPCo</td>
<td>2006-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>President and Chief Operating Officer of APCo, OPCo, PSO and SWEPCo</td>
<td>2004-2006</td>
</tr>
<tr>
<td>Carl L. English (a)</td>
<td>62</td>
<td>Chief Operating Officer, President-AEP Utilities of AEP, Director and Vice President of APCo, OPCo, PSO and SWEPCo</td>
<td>2008-2007, 2004-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>President and Chief Executive Officer of Consumers, Energy gas division</td>
<td>1999-2004</td>
</tr>
<tr>
<td>John B. Keane (c)</td>
<td>62</td>
<td>Executive Vice President, General Counsel and</td>
<td>2004-Present</td>
</tr>
<tr>
<td>Name</td>
<td>Age</td>
<td>Position</td>
<td>Period</td>
</tr>
<tr>
<td>---------------------------</td>
<td>-----</td>
<td>---------------------------------------------------------------------------</td>
<td>------------------</td>
</tr>
<tr>
<td>Holly Keller Koeppel</td>
<td>50</td>
<td>Secretary of AEP</td>
<td>2004-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director of APCo, OPCo, PSO and SWEPCo</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>President of Bainbridge Crossing Advisors</td>
<td>2003-2004</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Executive Vice President and Chief Financial Officer of AEP</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Executive Vice President-AEP Utilities-East of AEPSC</td>
<td>2004-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Vice President of APCo and OPCo</td>
<td>2003-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director of APCo and OPCo</td>
<td>2004-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Chief Financial Officer of APCo, OPCo, PSO and SWEPCo</td>
<td>2006-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Vice President and Director of PSO and SWEPCo</td>
<td>2006-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Executive Vice President-Commercial Operations of AEPSC</td>
<td>2002-2004</td>
</tr>
<tr>
<td>Venita McCellon-Allen</td>
<td>49</td>
<td>Executive Vice President</td>
<td>2008-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director and Vice President of PSO and SWEPCo</td>
<td>2008-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director and Chief Operating Officer of SWEPCo</td>
<td>2006-2008</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director and Senior Vice President-Shared Services of AEPSC</td>
<td>2004-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director of APCo, I&amp;M, OPCo and SWEPCo</td>
<td>2004-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Senior Vice President-Human Resources for Baylor Health Care Systems</td>
<td>2000-2004</td>
</tr>
<tr>
<td>Richard E. Munczinski</td>
<td>56</td>
<td>Senior Vice President-Shared Services</td>
<td>2008-Present</td>
</tr>
<tr>
<td>(c)</td>
<td></td>
<td>Senior Vice President-Corporate Planning &amp; Budgeting of AEPSC</td>
<td>1998-2008</td>
</tr>
<tr>
<td>Robert P. Powers</td>
<td>54</td>
<td>President-AEP Utilities of AEP</td>
<td>2008-Present</td>
</tr>
<tr>
<td>(a)</td>
<td></td>
<td>Executive Vice President of AEP</td>
<td>2004-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director and Vice President of APCo and OPCo</td>
<td>2001-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director and Vice President of PSO and SWEPCo</td>
<td>2008-Present</td>
</tr>
<tr>
<td>Brian X. Tierney</td>
<td>41</td>
<td>Executive Vice President</td>
<td>2008-Present</td>
</tr>
<tr>
<td>(a)</td>
<td></td>
<td>Director and Vice President of APCo and OPCo</td>
<td>2008-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Senior Vice President—Commercial Operations of AEPSC</td>
<td>2005-2007</td>
</tr>
<tr>
<td>Susan Tomasky</td>
<td>55</td>
<td>Senior Vice President—Energy Marketing of AEPSC</td>
<td>2003-2005</td>
</tr>
<tr>
<td>(a)</td>
<td></td>
<td>President-AEP Transmission</td>
<td>2008-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Executive Vice President of AEP</td>
<td>2004-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Chief Financial Officer of AEP</td>
<td>2001-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Vice President and Director of APCo, OPCo, PSO and SWEPCo</td>
<td>2000-Present</td>
</tr>
</tbody>
</table>

(a) Messrs. Morris, Akins, English, Powers and Tierney and Ms. Koeppel and Ms. Tomasky are directors of CSPCo and I&M.
(b) Mr. Morris is a director of Alcoa, Inc. and The Hartford Financial Services Group, Inc.
(c) Mr. Keane and Mr. Munczinski are directors of CSPCo.
(d) Ms. Koeppel is a director of Reynolds American Inc.
### APCo:

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Position</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dana E. Waldo</td>
<td>57</td>
<td>President and Chief Operating Officer of APCo</td>
<td>2004-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>President and Chief Executive Officer of West</td>
<td>1999-2004</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Virginia Roundtable</td>
<td></td>
</tr>
</tbody>
</table>

### OPCo:

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Position</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Joseph Hamrock</td>
<td>45</td>
<td>President and Chief Operating Officer of CSPCo and</td>
<td>2008-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>OPCo</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Senior Vice President and Chief Information Officer</td>
<td>2003-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>of AEPSC</td>
<td></td>
</tr>
</tbody>
</table>

### PSO:

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Position</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stuart Solomon</td>
<td>47</td>
<td>President and Chief Operating Officer of PSO</td>
<td>2004-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Vice President-Public Policy &amp; Regulatory Services</td>
<td>2001-2004</td>
</tr>
<tr>
<td></td>
<td></td>
<td>of AEPSC</td>
<td></td>
</tr>
</tbody>
</table>

### SWEPCo:

<table>
<thead>
<tr>
<th>Name</th>
<th>Age</th>
<th>Position</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Paul Chodak, III</td>
<td>45</td>
<td>President and Chief Operating Officer of SWEPCo</td>
<td>2008-Present</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director-New Generation of AEPSC</td>
<td>2007-2008</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Director-Environmental Programs of AEPSC</td>
<td>2004-2007</td>
</tr>
</tbody>
</table>
PART II

ITEM 5. MARKET FOR REGISTRANTS’ COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP. The information required by this item is incorporated herein by reference to the material under AEP Common Stock and Dividend Information in the 2008 Annual Report.

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2008, 2007 and 2006 are incorporated by reference to the material under Statements of Changes in Common Shareholder’s Equity and Comprehensive Income (Loss) in the 2008 Annual Reports.

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended December 31, 2008 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

<table>
<thead>
<tr>
<th>Period</th>
<th>Total Number of Shares Purchased</th>
<th>Average Price Paid per Share</th>
<th>Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs</th>
<th>Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs</th>
</tr>
</thead>
<tbody>
<tr>
<td>10/01/08 – 10/31/08</td>
<td>-</td>
<td>$</td>
<td>-</td>
<td>$</td>
</tr>
<tr>
<td>11/01/08 – 11/30/08</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>12/01/08 – 12/31/08</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$</td>
</tr>
</tbody>
</table>

ITEM 6. SELECTED FINANCIAL DATA

CSPCo and I&M. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the 2008 Annual Reports.
ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

CSPCo and I&M. Omitted pursuant to Instruction I(2)(a). Management’s narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management’s Financial Discussion and Analysis of Results of Operations in the 2008 Annual Reports.

AEP, APCo, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under Management’s Financial Discussion and Analysis of Results of Operations in the 2008 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under Management’s Financial Discussion and Analysis of Results of Operations in the 2008 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2008, management, including the principal executive officer and principal financial officer of each of 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 (each a “Registrant” and collectively the “Registrants”) evaluated each respective Registrant’s disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant’s management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2008, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The
Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants’ internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2008 that materially affected, or are reasonably likely to materially affect, the Registrants’ internal controls over financial reporting.

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2008. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2008 and, therefore, concluded that each Registrant’s internal control over financial reporting was effective.

Additional information required by this item of the Registrants is incorporated by reference to Management's Report on Internal Control over Financial Reporting, included in the 2008 Annual Report of each Registrant.

ITEM 9B. OTHER INFORMATION

None.
PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).

AEP:

Directors, Director Nomination Process and Audit Committee. The information required by this item concerning directors and nominees for election as directors at AEP’s annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)) and the audit committee (Item 407(d)(4) and (d)(5)) is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2009 annual meeting of shareholders.

Executive Officers. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I, Item 4 of this report.

Code of Ethics. AEP’s Principles of Business Conduct is the code of ethics that applies to AEP’s Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP’s website at www.aep.com. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP’s website, www.aep.com, or in a report on Form 8-K.

Beneficial Ownership Reporting Compliance. The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2009 annual meeting of shareholders.

APCo, OPCo, PSO and SWEPCo:

Directors and Executive Officers. The information required by this item is incorporated herein by reference to the information in the definitive information statement of each company for the 2009 annual meeting of stockholders. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I, Item 4 of this report.

Audit Committee. Each of APCo, OPCo, PSO and SWEPCo is a controlled subsidiary of AEP and does not have a separate audit committee.

Code of Ethics. AEP’s Principles of Business Conduct is the code of ethics that applies to the Chief Executive Officer, Chief Financial Officer and principal accounting officer of APCo, OPCo, PSO and SWEPCo. The discussion of AEP’s Principles of Business Conduct above is incorporated herein by reference. If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to the Chief Executive Officer, Chief Financial Officer or principal accounting officer of APCo, OPCo, PSO and SWEPCo, as applicable, that company will disclose the nature of such amendment or waiver on AEP’s website, www.aep.com, or in a report on Form 8-K.
ITEM 11. EXECUTIVE COMPENSATION

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under Directors Compensation and Stock Ownership, Executive Compensation of the definitive proxy statement of AEP for the 2009 annual meeting of shareholders and the 2008 Annual Reports, page (vi).

APCo, OPCo, PSO and SWEPCO. The information required by this item is incorporated herein by reference to the material under Executive Compensation of the definitive information statement of each company for the 2009 annual meeting of stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under Share Ownership of Directors and Executive Officers of the definitive proxy statement of AEP for the 2009 annual meeting of shareholders.

APCo, OPCo, PSO and SWEPCO. The information required by this item is incorporated herein by reference to the material under Share Ownership of Directors and Executive Officers in the definitive information statement of each company for the 2009 annual meeting of stockholders.

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2008:

<table>
<thead>
<tr>
<th>Plan Category</th>
<th>Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)</th>
<th>Weighted average exercise price of outstanding options, warrants and rights (b)</th>
<th>Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity compensation plans approved by security holders(1)</td>
<td>1,128,219</td>
<td>$32.73</td>
<td>14,817,545</td>
</tr>
<tr>
<td>Equity compensation plans not approved by security holders</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>1,128,219</td>
<td>$32.73</td>
<td>14,817,545</td>
</tr>
</tbody>
</table>

(1) Consists of shares to be issued upon exercise of outstanding options granted under the Amended and Restated American Electric Power System Long-Term Incentive Plan.
ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

CSPCo and I&M: Omitted pursuant to Instruction I(2)(c).

AEP: The information required by this item is incorporated herein by reference to the definitive proxy statement of AEP for the 2009 annual meeting of shareholders.

APCo, OPCo, PSO and SWEPCo: Certain Relationships and Related Transactions. None.

Director Independence. None of the directors of APCo, OPCo, PSO or SWEPCo is independent because each director is either (i) an officer of the company in which each serves as director, or (ii) an officer of AEP.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP. The following table presents fees for professional audit services rendered by Deloitte & Touche LLP for the audit of AEP’s annual financial statements for the years ended December 31, 2008 and December 31, 2007, and fees billed for other services rendered by Deloitte & Touche LLP during those periods.

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Audit Fees (1)</td>
<td>$11,762,000</td>
<td>$11,747,000</td>
</tr>
<tr>
<td>Audit-Related Fees (2)</td>
<td>1,184,000</td>
<td>1,456,000</td>
</tr>
<tr>
<td>Tax Fees (3)</td>
<td>697,000</td>
<td>1,820,000</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$13,643,000</td>
<td>$15,023,000</td>
</tr>
</tbody>
</table>

(1) Audit fees in 2007 and 2008 consisted primarily of fees related to the audit of the Company’s annual consolidated financial statements, including each registrant subsidiary. Audit fees also included auditing procedures performed in accordance with Sarbanes-Oxley Act Section 404 and the related Public Company Accounting Oversight Board Auditing Standard Number 5 regarding the Company’s internal control over financial reporting. This category also includes work generally only the independent registered public accounting firm can reasonably be expected to provide.

(2) Audit related fees consisted principally of regulatory, statutory, employee benefit plan audits, and audit-related work in connection with acquisitions, dispositions, and new ventures.

(3) Tax fees consisted principally of tax compliance services. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings. The decrease from 2007 relates primarily to additional work performed in 2007 to assist the Company in connection with an approved change in accounting method from the Internal Revenue Service.

APCo, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2009 annual meeting of stockholders.
CSPCo and I&M.

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2009 annual meeting of shareholders. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies’ annual financial statements for the years ended December 31, 2007 and 2008, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the definitive proxy statement of AEP for the 2009 annual meeting of shareholders.

<table>
<thead>
<tr>
<th></th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Audit Fees</td>
<td>$1,092,225</td>
<td>$1,333,878</td>
</tr>
<tr>
<td>Audit-Related Fees</td>
<td>109,947</td>
<td>51,072</td>
</tr>
<tr>
<td>Tax Fees</td>
<td>64,724</td>
<td>58,621</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$1,266,896</td>
<td>$1,443,571</td>
</tr>
</tbody>
</table>
## PART IV

### ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

<table>
<thead>
<tr>
<th>1. FINANCIAL STATEMENTS:</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>The following financial statements have been incorporated herein by reference pursuant to Item 8.</td>
<td></td>
</tr>
<tr>
<td><strong>AEP and Subsidiary Companies:</strong></td>
<td></td>
</tr>
<tr>
<td><strong>APCo, CSPCo, I&amp;M, OPCo and SWEPCo:</strong></td>
<td></td>
</tr>
<tr>
<td><strong>PSO:</strong></td>
<td></td>
</tr>
<tr>
<td>2. FINANCIAL STATEMENT SCHEDULES:</td>
<td>S-1</td>
</tr>
<tr>
<td>Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Report of Independent Registered Public Accounting Firm</td>
<td></td>
</tr>
<tr>
<td>3. EXHIBITS:</td>
<td>E-1</td>
</tr>
<tr>
<td>Exhibits for AEP, APCo, CSPCo, I&amp;M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference</td>
<td></td>
</tr>
</tbody>
</table>
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ HOLLY KELLER KOEPPEL
   (Holly Keller Koeppel, Executive Vice President
   and Chief Financial Officer)

Date: February 27, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<table>
<thead>
<tr>
<th>Signature</th>
<th>Title</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i) Principal Executive Officer:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ MICHAEL G. MORRIS</td>
<td>Chairman of the Board, President, Chief Executive Officer And Director</td>
<td>February 27, 2009</td>
</tr>
<tr>
<td>(Michael G. Morris)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(ii) Principal Financial Officer:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ HOLLY KELLER KOEPPEL</td>
<td>Executive Vice President and Chief Financial Officer</td>
<td>February 27, 2009</td>
</tr>
<tr>
<td>(Holly Keller Koeppel)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(iii) Principal Accounting Officer:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>/s/ JOSEPH M. BUONAIUTO</td>
<td>Senior Vice President, Controller and Chief Accounting Officer</td>
<td>February 27, 2009</td>
</tr>
<tr>
<td>(Joseph M. Buonaiuto)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(iv) A Majority of the Directors:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E. R. BROOKS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DONALD M. CARLTON</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RALPH D. CROSBY, JR.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LINDA A. GOODSPEED</td>
<td></td>
<td></td>
</tr>
<tr>
<td>THOMAS E. HOAGLIN</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LESTER A. HUDSON, JR.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SARA MARTINEZ TUCKER</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LIONEL L. NOWELL, III</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RICHARD L. SANDOR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>KATHRYN D. SULLIVAN</td>
<td></td>
<td></td>
</tr>
<tr>
<td>JOHN F. TURNER</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*By: /s/ HOLLY KELLER KOEPPEL
   (Holly Keller Koeppel, Attorney-in-Fact)

February 27, 2009
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ HOLLY KELLER KOEPPEL
(Holly Keller Koeppel, Vice President and Chief Financial Officer)

Date: February 27, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

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<tbody>
<tr>
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<td></td>
<td></td>
</tr>
<tr>
<td>/s/ MICHAEL G. MORRIS</td>
<td>Chairman of the Board, Chief Executive Officer and Director</td>
<td>February 27, 2009</td>
</tr>
<tr>
<td>(Michael G. Morris)</td>
<td></td>
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<td></td>
</tr>
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<td>February 27, 2009</td>
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<tr>
<td>(Holly Keller Koeppel)</td>
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<td>(iii) Principal Accounting Officer:</td>
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<tr>
<td>/s/ JOSEPH M. BUONAIUTO</td>
<td>Controller and Chief Accounting Officer</td>
<td>February 27, 2009</td>
</tr>
<tr>
<td>(Joseph M. Buonaiuto)</td>
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</tr>
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<td>(iv) A Majority of the Directors:</td>
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</tr>
<tr>
<td>*NICHOLAS K. AKINS</td>
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<td>*CARL L. ENGLISH</td>
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<tr>
<td>*JOHN B. KEANE</td>
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<tr>
<td>*VENITA McCELLON-ALLEN</td>
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<tr>
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<tr>
<td>*DENNIS E. WELCH</td>
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*By: /s/ HOLLY KELLER KOEPPEL
(Holly Keller Koeppel, Attorney-in-Fact) February 27, 2009
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused
this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned
company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY

By: /s/ HOLLY KELLER KOEPEL
(Holly Keller Koeppel, Vice President
and Chief Financial Officer)

Date: February 27, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following
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INDIANA MICHIGAN POWER COMPANY

By: /s/ HOLLY KELLER KOEPPEL  
(Holly Keller Koeppel Vice President and Chief Financial Officer)

Date: February 27, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

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<td>February 27, 2009</td>
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(ii) Principal Financial Officer:

/s/ HOLLY KELLER KOEPPEL  
(Holly Keller Koeppel)

Vice President,  
Chief Financial Officer and Director  
February 27, 2009

(iii) Principal Accounting Officer:

/s/ JOSEPH M. BUONAIUTO  
(Joseph M. Buonaiuto)

Controller and  
Chief Accounting Officer  
February 27, 2009

(iv) A Majority of the Directors:

*NICHOLAS K. AKINS  
*KENT D. CURRY  
*J. EDWARD EHLER  
*CARL L. ENGLISH  
*ALLEN R. GLASSBURN  
*JOANN M. GREVENOW  
*PATRICK C. HALE  
*MARCE E. LEWIS  
*HELEN J. MURRAY  
*ROBERT P. POWERS  
*SUSANNE M. MOORMAN ROWE  
BRIAN X. TIERNEY  
*SUSAN TOMASKY

*By: /s/ HOLLY KELLER KOEPPEL  
(Holly Keller Koeppel, Attorney-in-Fact)  
February 27, 2009
INDEX TO FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM S-2

The following financial statement schedules are included in this report on the pages indicated:

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
   Schedule II — Valuation and Qualifying Accounts and Reserves S-3

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
   Schedule II — Valuation and Qualifying Accounts and Reserves S-3

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
   Schedule II — Valuation and Qualifying Accounts and Reserves S-3

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
   Schedule II — Valuation and Qualifying Accounts and Reserves S-4

OHIO POWER COMPANY CONSOLIDATED
   Schedule II — Valuation and Qualifying Accounts and Reserves S-4

PUBLIC SERVICE COMPANY OF OKLAHOMA
   Schedule II — Valuation and Qualifying Accounts and Reserves S-4

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
   Schedule II — Valuation and Qualifying Accounts and Reserves S-5
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the “Company”) as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and the Company's internal control over financial reporting as of December 31, 2008, and have issued our reports thereon dated February 27, 2009 (which reports express unqualified opinions and, with respect to the report on the consolidated financial statements, includes an explanatory paragraph concerning the adoption of new accounting pronouncements in 2007 and 2006); such consolidated financial statements and reports are included in your 2008 Annual Report and are incorporated herein by reference. Our audits also included the consolidated financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the consolidated financial statements of Appalachian Power Company and subsidiaries, Columbus Southern Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively the “Companies”) as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and have issued our reports thereon dated February 27, 2009 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2007 and 2006); such financial statements and reports are included in your 2008 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies’ management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
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<thead>
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<tr>
<td></td>
<td>Balance at Beginning of Period</td>
<td>Additions</td>
<td>Charged to Costs and Expenses</td>
<td>Charged to Other Accounts (a)</td>
<td>Deductions (b)</td>
</tr>
<tr>
<td>Deducted from Assets:</td>
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<td></td>
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<td></td>
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<tr>
<td>Accumulated Provision for Uncollectible Accounts:</td>
<td></td>
<td></td>
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<tr>
<td>Year Ended December 31, 2008 $52,046</td>
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<td>(a) Recoveries on accounts previously written off.</td>
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**APPALACHIAN POWER COMPANY AND SUBSIDIARIES**

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<td></td>
<td></td>
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<td></td>
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<tr>
<td>Year Ended December 31, 2008 $13,948</td>
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<td>Year Ended December 31, 2007 4,334</td>
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<td>Year Ended December 31, 2006 1,805</td>
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<tr>
<td>(a) Recoveries on accounts previously written off.</td>
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<tr>
<td>(b) Uncollectible accounts written off.</td>
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**COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES**

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<td>Accumulated Provision for Uncollectible Accounts:</td>
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<tr>
<td>Year Ended December 31, 2008 $2,563</td>
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<tr>
<td>(a) Recoveries on accounts previously written off.</td>
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### INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES**

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</tr>
<tr>
<td>Uncollectible Accounts:</td>
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</table>

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

### OHIO POWER COMPANY CONSOLIDATED

**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES**

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<tr>
<td>Uncollectible Accounts:</td>
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</table>

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

### PUBLIC SERVICE COMPANY OF OKLAHOMA

**SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES**

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(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Includes a credit of $81 thousand from a true-up adjustment as a result of changes to the System Integration Agreement and the CSW Operating Agreement.
**Deducted from Assets:**

Accumulated Provision for Uncollectible Accounts:

<table>
<thead>
<tr>
<th>Year Ended December 31,</th>
<th>Balance at Beginning of Period</th>
<th>Charged to Costs and Expenses</th>
<th>Charged to Other Accounts (a)</th>
<th>Deductions (b)</th>
<th>Balance at End of Period</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year Ended December 31, 2008</td>
<td>$ 143</td>
<td>$</td>
<td>$</td>
<td>$ 8</td>
<td>$ 135</td>
</tr>
<tr>
<td>Year Ended December 31, 2007</td>
<td>130</td>
<td>23</td>
<td>-</td>
<td>10</td>
<td>143</td>
</tr>
<tr>
<td>Year Ended December 31, 2006</td>
<td>548</td>
<td>(37) (c)</td>
<td>-</td>
<td>381</td>
<td>130</td>
</tr>
</tbody>
</table>

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Includes a credit of $95 thousand from a true-up adjustment as a result of changes to the System Integration Agreement and the CSW Operating Agreement.
The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits (“Ex”) not identified as previously filed are filed herewith. Exhibits, designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form pursuant to Item 14(c) of this report.

<table>
<thead>
<tr>
<th>Exhibit Designation</th>
<th>Nature of Exhibit</th>
<th>Previously Filed as Exhibit to:</th>
</tr>
</thead>
<tbody>
<tr>
<td>REGISTRANT: AEP‡</td>
<td>File No. 1-3525</td>
<td>1998 Form 10-K, Ex 3(c)</td>
</tr>
<tr>
<td>3(a)</td>
<td>Composite of the Restated Certificate of Incorporation of AEP, dated January 13, 1999.</td>
<td>2007 Form 10-K, Ex 3(b)</td>
</tr>
<tr>
<td>3(b)</td>
<td>Composite By-Laws of AEP, as amended as of December 12, 2007.</td>
<td>Registration Statement No. 333-86050, Ex 4(a)(b)(c)</td>
</tr>
<tr>
<td>4(a)</td>
<td>Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.</td>
<td>Registration Statement No. 333-105532, Ex 4(d)(e)(f)</td>
</tr>
<tr>
<td>4(b)</td>
<td>Purchase Agreement dated as of March 8, 2005, between AEP and Merrill Lynch International.</td>
<td>Form 10-Q, Ex 4(a), March 31, 2005</td>
</tr>
<tr>
<td>4(c)</td>
<td>Junior Subordinated Indenture dated as of March 1, 2008 between AEP and The Bank of New York as Trustee.</td>
<td>Registration Statement 333-156387, Ex 4(c)(d)</td>
</tr>
<tr>
<td>4(d)</td>
<td>Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(a) September 30, 2008</td>
</tr>
<tr>
<td>4(e)</td>
<td>Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Barclays Bank plc as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(b) September 30, 2008</td>
</tr>
<tr>
<td>4(f)</td>
<td>$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(c) September 30, 2008</td>
</tr>
<tr>
<td>4(g)</td>
<td>Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(d) September 30, 2008</td>
</tr>
<tr>
<td>4(h)</td>
<td>$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(e) September 30, 2008</td>
</tr>
<tr>
<td>4(i)</td>
<td>Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(f) September 30, 2008</td>
</tr>
<tr>
<td>Exhibit Designation</td>
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<tr>
<td>---------------------</td>
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<td>-----------------------------------------------------------------------------------------------</td>
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</tbody>
</table>
| 10(a)               | Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended. | Registration Statement No. 2-52910, Ex 5(a)  
Registration Statement No. 2-61009, Ex 5(b)  
1990 Form 10-K, Ex 10(a)(3) |
| 10(b)               | Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006. | Form 10-Q, Ex 10(b), March 31, 2006 |
| 10(c)               | Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended. | 1985 Form 10-K, Ex 10(b)  
1988 Form 10-K, Ex 10(b)(2) |
| 10(d)               | Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC. | 2002 Form 10-K, Ex 10(d) |
| 10(e)(1)            | Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company. | 2004 Form 10-K, Ex 10(e)(1) |
| 10(e)(2)            | PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area. | 2004 Form 10-K, Ex 10(e)(2) |
| 10(e)(3)            | Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company. | 2004 Form 10-K, Ex 10(e)(3) |
| 10(f)               | Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended. | Registration Statement No. 33-32752, Ex 28(c)(1-6)(C)  
Registration Statement No. 33-32753, Ex 28(a)(1-6)(C)  
AEGCo 1993 Form 10-K, Ex 10(c)(1-6)(B)  
I&M 1993 Form 10-K, Ex 10(e)(1-6)(B) |
<p>| 10(g)               | Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested). | OPCo 1994 Form 10-K, Ex 10(l)(2) |
| 10(h)               | Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&amp;M, KPCo, OPCo and AEPSC. | 1996 Form 10-K, Ex 10(l) |
| 10(i)               | Consent Decree with U.S. District Court. | Form 8-K, Ex 10.1 dated October 9, 2007 |
| †10(j)              | AEP Accident Coverage Insurance Plan for Directors. | 1985 Form 10-K, Ex 10(g) |
| †10(k)(1)           | AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended February 9, 2007. | 2007 Form 10-K, Ex 10(j)(i) |
| †10(k)(2)           | AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended. | 2003 Form 10-K, Ex 10(k)(2) |
| †10(k)(2)(A)        | First Amendment to AEP Stock Unit Accumulation Plan for Non-Employee Directors dated as of February 9, 2007. | 2006 Form 10-K, Ex 10(j)(2)(A) |
| *†10(l)(2)          | AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008 (Non-Qualified). | 1993 Form 10-K, Ex 10(g)(3) |
| †10(l)(3)           | AEPSC Umbrella Trust for Executives. | 1993 Form 10-K, Ex 10(g)(3) |
| *†10(l)(3)(A)       | First Amendment to AEPSC Umbrella Trust for Executives. | 2003 Form 10-K, Ex 10(m)(1) |
| *†10(m)(1)(A)       | Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008. | 2000 Form 10-K, Ex 10(s) |
| †10(m)(2)           | Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001. | 2000 Form 10-K, Ex 10(s) |
| †10(m)(3)           | Letter Agreement dated June 23, 2000 between AEPSC | 2002 Form 10-K, Ex 10(m)(3)(A) |</p>
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<td>*†10(m)(4)(A)</td>
<td>Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.</td>
<td>Form 10-K, Ex 10(l)(6)</td>
</tr>
<tr>
<td>†10(m)(5)</td>
<td>Letter Agreement dated June 9, 2004 between AEPSC and Carl English.</td>
<td>Form 10-Q, Ex 10(b), September 30, 2004</td>
</tr>
<tr>
<td>†10(m)(6)</td>
<td>Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane.</td>
<td>2006 Form 10-K, Ex 10(l)(6)</td>
</tr>
<tr>
<td>†10(n)</td>
<td>AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.</td>
<td>Form 8-K, Ex 10.1 dated April 25, 2007</td>
</tr>
<tr>
<td>†10(o)(1)(A)</td>
<td>First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.</td>
<td>2002 Form 10-K, Ex 10(o)(2)</td>
</tr>
<tr>
<td>*†10(o)(1)(B)</td>
<td>Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.</td>
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<tr>
<td>†10(p)</td>
<td>AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.</td>
<td></td>
</tr>
<tr>
<td>†10(q)</td>
<td>AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.</td>
<td>2002 Form 10-K, Ex 10(r)</td>
</tr>
<tr>
<td>†10(r)</td>
<td>Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.</td>
<td></td>
</tr>
<tr>
<td>††10(s)</td>
<td>AEP Change In Control Agreement, effective January 1, 2008.</td>
<td>2007 Form 10-K, Ex 10(s)</td>
</tr>
<tr>
<td>†10(t)(1)</td>
<td>Amended and Restated AEP System Long-Term Incentive Plan.</td>
<td>Form 8-K, Item 1.01, dated April 26, 2005</td>
</tr>
<tr>
<td>†10(t)(1)(A)</td>
<td>First Amendment to Amended and Restated AEP System Long-Term Incentive Plan.</td>
<td>2007 Form 10-K, Ex 10(t)(1)(A)</td>
</tr>
<tr>
<td>†10(t)(2)</td>
<td>Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
<td>Form 10-Q, Ex 10(c), September 30, 2004</td>
</tr>
<tr>
<td>†10(t)(3)</td>
<td>Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
<td>Form 10-Q, Ex 10(a), March 31, 2005</td>
</tr>
<tr>
<td>*†10(t)(3)(A)</td>
<td>Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
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<tr>
<td>*†10(u)</td>
<td>AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2008.</td>
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</tr>
<tr>
<td>*†10(v)</td>
<td>Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.</td>
<td></td>
</tr>
<tr>
<td>*12</td>
<td>Statement re: Computation of Ratios.</td>
<td></td>
</tr>
<tr>
<td>*13</td>
<td>Copy of those portions of the AEP 2008 Annual Report (for the fiscal year ended December 31, 2008) which are incorporated by reference in this filing.</td>
<td></td>
</tr>
<tr>
<td>*21</td>
<td>List of subsidiaries of AEP.</td>
<td></td>
</tr>
<tr>
<td>*23</td>
<td>Consent of Deloitte &amp; Touche LLP.</td>
<td></td>
</tr>
<tr>
<td>*24</td>
<td>Power of Attorney.</td>
<td></td>
</tr>
<tr>
<td>*31(a)</td>
<td>Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</td>
<td></td>
</tr>
<tr>
<td>*31(b)</td>
<td>Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</td>
<td></td>
</tr>
<tr>
<td>Exhibit Designation</td>
<td>Nature of Exhibit</td>
<td>Previously Filed as Exhibit to:</td>
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<tr>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>*32(a)</td>
<td>Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.</td>
<td></td>
</tr>
<tr>
<td>*32(b)</td>
<td>Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.</td>
<td></td>
</tr>
</tbody>
</table>

**REGISTRANT: APCo‡ File No. 1-3457**

<table>
<thead>
<tr>
<th>3(a)</th>
<th>Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.</th>
<th>1996 Form 10-K, Ex 3(d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3(b)</td>
<td>Composite By-Laws of APCo, amended as of February 26, 2008.</td>
<td>2007 Form 10-K, Ex 3(b)</td>
</tr>
</tbody>
</table>
| 4(a)                | Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee. | Registration Statement No. 333-45927, Ex 4(a)(b)  
Registration Statement No. 333-49071, Ex 4(b)  
Registration Statement No. 333-84061, Ex 4(b)(c)  
Registration Statement No. 333-100451, Ex 4(b)(c)(d)  
Registration Statement No. 333-116284, Ex 4(b)(c)  
Registration Statement No. 333-123348, Ex 4(b)(c)  
Registration Statement No. 333-136432, Ex 4(b)(c)(d) |
| 4(b)                | Company Order and Officer’s Certificate to The Bank of New York, dated August 17, 2007 establishing terms of 5.65% Senior Notes Series O due 2012 and 6.70% Senior Notes Series P due 2037. | Form 8-K, Ex 4(a) dated August 17, 2007                                                                                                               |
| 4(c)                | Company Order and Officer’s Certificate to The Bank of New York, dated March 25, 2008 establishing terms of 7.00% Senior Notes Series Q due 2038. | Form 8-K, Ex 4(a) dated March 25, 2008                                                                                                               |
| 4(d)                | $650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPcO, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. | Form 10-Q, Ex. 10(c) September 30, 2008                                                         |
| 4(e)                | Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPcO, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. | Form 10-Q, Ex. 10(d) September 30, 2008                                                         |
| 4(f)                | $350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPcO, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. | Form 10-Q, Ex. 10(e) September 30, 2008                                                         |
| 4(g)                | Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPcO, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. | Form 10-Q, Ex. 10(f) September 30, 2008                                                         |
| 10(a)(1)            | Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of | Registration Statement No. 2-60015, Ex 5(a)  
Registration Statement No. 2-63234, Ex 5(a)(1)(B)  
Registration Statement No 2-66301, Ex 5(a)(1)(C)  
Registration Statement No. 2-67728, Ex 5(a)(1)(D) |

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*10(a)(1) is a misprint, it should be 10(a)(1).*
<table>
<thead>
<tr>
<th>Exhibit Designation</th>
<th>Nature of Exhibit</th>
<th>Previously Filed as Exhibit to:</th>
</tr>
</thead>
</table>
| 10(a)(2)            | Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended. | 1989 Form 10-K, Ex 10(a)(1)(F)  
1992 Form 10-K, Ex 10(a)(1)(B) |
| 10(a)(3)            | Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended. | Registration Statement No. 2-60015, Ex 5(e) |
| 10(b)               | Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended. | Registration Statement No. 2-52910, Ex 5(a)  
Registration Statement No. 2-61009, Ex 5(b)  
AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525 |
| 10(c)               | Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended. | AEP 1985 Form 10-K, Ex 10(b)  
AEP 1988 Form 10-K, Ex 10(b)(2) |
| 10(d)(1)            | Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company. | 2004 Form 10-K, Ex 10(d)(1) |
| 10(d)(2)            | PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area. | 2004 Form 10-K, Ex 10(d)(2) |
| 10(d)(3)            | Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company. | 2004 Form 10-K, Ex 10(d)(3) |
| 10(e)               | Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC. | AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525 |
| 10(f)               | Consent Decree with U.S. District Court. | Form 8-K, Ex 10.1 dated October 9, 2007 |
| †10(g)              | AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006. | Form 8-K, Ex 10.1 dated April 25, 2007 |
| *†10(h)(1)          | AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008. | AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525 |
| *†10(h)(2)          | AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008 (Non-Qualified). | AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525 |
| †10(h)(3)           | AEPSC Umbrella Trust for Executives. | AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525 |
| *†10(h)(3)(A)       | First Amendment to AEPSC Umbrella Trust for Executives. | AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525 |
| *†10(i)(A)          | Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008. | AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525 |
| †10(i)(3)           | Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel. | 2002 Form 10-K, Ex 10(m)(4) |
| *†10(i)(4)(A)       | Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers. | AEP 10-Q, Ex 10(b), September 30, 2004  
AEP 2006 Form 10-K, Ex 10(h)(5) |
<p>| †10(i)(6)           | Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane. | Form 8-K, Ex 10.1 dated April 25, 2007 |</p>
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<td>†10(k)(1)(A)</td>
<td>First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.</td>
<td>2002 Form 10-K, Ex 10(o)(2)</td>
</tr>
<tr>
<td>*↑10(k)(1)(B)</td>
<td>Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.</td>
<td></td>
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<tr>
<td>†10(l)</td>
<td>AEP Change In Control Agreement, effective January 1, 2008.</td>
<td>2007 Form 10-K, Ex 10(k)</td>
</tr>
<tr>
<td>†10(m)(1)</td>
<td>Amended and Restated AEP System Long-Term Incentive Plan.</td>
<td>Form 8-K, Ex 10.1, dated April 26, 2005</td>
</tr>
<tr>
<td>10(m)(1)(A)</td>
<td>First Amendment to Amended and Restated AEP System Long-Term Incentive Plan.</td>
<td>2007 Form 10-K, Ex 10(l)(1)(A)</td>
</tr>
<tr>
<td>†10(m)(2)</td>
<td>Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
<td>AEP Form 10-Q, Ex 10(c), dated November 5, 2004</td>
</tr>
<tr>
<td>†10(m)(3)</td>
<td>Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
<td>AEP Form 10-Q, Ex 10(a), March 31, 2005</td>
</tr>
<tr>
<td>*↑10(m)(3)(A)</td>
<td>Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
<td></td>
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<tr>
<td>†10(m)(4)</td>
<td>AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2008.</td>
<td></td>
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<td>Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.</td>
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<td>*↑10(o)</td>
<td>AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.</td>
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</tr>
<tr>
<td>†10(p)</td>
<td>AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.</td>
<td>2002 Form 10-K, Ex 10(r)</td>
</tr>
<tr>
<td>*↑10(q)</td>
<td>Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008</td>
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<td>Statement re: Computation of Ratios.</td>
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**REGISTRANT:** CSPCo‡  **File No. I-2680**

<p>| 3(a) | Composite of Amended Articles of Incorporation of CSPCo, dated May 19, 1994. | AEP 1994 Form 10-K, Ex 3(c) |
| 3(b) | Amended Code of Regulations of CSPCo.                                      | Form 10-Q, Ex 3(b) June 30, 2008 |</p>
<table>
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<th><strong>Exhibit Designation</strong></th>
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<tr>
<td>4(a)</td>
<td>Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee.</td>
<td>Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d)</td>
</tr>
<tr>
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<td>Registration Statement No. 333-128174, Ex 4(b)(c)(d)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Registration Statement No. 333-150603, Ex 4(b)</td>
</tr>
<tr>
<td>4(b)</td>
<td>Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee.</td>
<td>Registration Statement No. 333-128174, Ex 4(e)(f)(g)</td>
</tr>
<tr>
<td>4(c)</td>
<td>Company Order and Officer’s Certificate to Deutsche Bank Trust Company Americas, dated October 14, 2005, establishing terms of 5.85% senior Notes, Series F, due 2035.</td>
<td>Form 8-K, Ex 4(a), dated October 14, 2005</td>
</tr>
<tr>
<td>4(e)</td>
<td>$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(c) September 30, 2008</td>
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<td>4(f)</td>
<td>Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(d) September 30, 2008</td>
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<tr>
<td>4(g)</td>
<td>$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(e) September 30, 2008</td>
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<td>4(h)</td>
<td>Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(f) September 30, 2008</td>
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<td>10(a)(1)</td>
<td>Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.</td>
<td>Registration Statement No. 2-60015, Ex 5(a)</td>
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<td>Registration Statement No. 2-63234, Ex 5(a)(1)(B)</td>
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<td>Registration Statement No. 2-66301, Ex 5(a)(1)(C)</td>
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<td>Registration Statement No. 2-67728, Ex 5(a)(1)(B)</td>
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<td>APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457</td>
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<td>APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No.1-3457</td>
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<tr>
<td>10(a)(3)</td>
<td>Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.</td>
<td>Registration Statement No. 2-60015, Ex 5(e)</td>
</tr>
<tr>
<td>10(b)(1)</td>
<td>Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&amp;M and AEPSC, as amended.</td>
<td>Registration Statement No. 2-52910, Ex 5(a)</td>
</tr>
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<td>Registration Statement No. 2-61009, Ex 5(b)</td>
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<td>1990 Form 10-K, Ex 10(a)(3), File No. 1-3525</td>
</tr>
<tr>
<td>10(b)(2)</td>
<td>Unit Power Agreement, dated March 15, 2007 between</td>
<td>2007 Form 10-K, Ex 10(b)(2)</td>
</tr>
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<td>Exhibit Designation</td>
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| 10(c)               | Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC as agent, as amended. | AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525  
AEP 1988 Form 10-K, Ex 10(b)(2) File No. 1-3525 |
| 10(d)(1)            | Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company. | 2004 Form 10-K, Ex 10(d)(1) |
| 10(d)(2)            | PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area. | 2004 Form 10-K, Ex 10(d)(2) |
| 10(d)(3)            | Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company. | 2004 Form 10-K, Ex 10(d)(3) |
| 10(e)               | Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC. | AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525 |
| 10(f)               | Consent Decree with U.S. District Court. | Form 8-K, Ex 10.1 dated October 9, 2007 |
| *12                 | Statement re: Computation of Ratios. | |
| *13                 | Copy of those portions of the CSPCo 2008 Annual Report (for the fiscal year ended December 31, 2008) which are incorporated by reference in this filing. | |
| 21                  | List of subsidiaries of CSPCo. | AEP 2006 Form 10-K, Ex 21, File No. 1-3525 |
| *23                 | Consent of Deloitte & Touche LLP. | |
| *24                 | Power of Attorney. | |
| *31(a)              | Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. | |
| *31(b)              | Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. | |
| *32(a)              | Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code. | |
| *32(b)              | Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code. | |
| **REGISTRANT:**     | **I&M‡File No. 1-3570** | |
| 3(a)                | Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997. | 1996 Form 10-K, Ex 3(c) |
| 3(b)                | Composite By-Laws of I&M, amended as of February 26, 2008. | 2007 Form 10-K, Ex 3(b) |
| 4(a)                | Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee. | Registration Statement No. 333-88523, Ex 4(a)(b)(c)  
Registration Statement No. 333-58656, Ex 4(b)(c)  
Registration Statement No. 333-108975, Ex 4(b)(c)(d)  
Registration Statement No. 333-136538, Ex 4(b)(c)  
Registration Statement No. 333-156182, Ex 4(b) |
<p>| 4(b)                | Company Order and Officer’s Certificate to The Bank of New York, dated November 14, 2006, establishing terms of 6.05% Senior Notes, Series H, due 2037. | Form 8-K, Ex 4(a), dated November 14, 2006 |
| 4(c)                | Company Order and Officer’s Certificate to The Bank of New York, dated January 15, 2009 establishing terms of 7.00% Senior Notes, Series I due 2019. | Form 8-K, Ex 4(a) dated January 15, 2009 |
| 4(d)                | $650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the | Form 10-Q, Ex. 10(c) September 30, 2008 |</p>
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<td>Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(d) September 30, 2008</td>
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<td>4(f)</td>
<td>$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(e) September 30, 2008</td>
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<td>4(g)</td>
<td>Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(f) September 30, 2008</td>
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<tr>
<td>10(a)(3)</td>
<td>Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.</td>
<td>Registration Statement No. 2-60015, Ex 5(e)</td>
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<td>10(b)(1)</td>
<td>Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&amp;M, and OPCo and with AEPSC, as amended.</td>
<td>Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525</td>
</tr>
<tr>
<td>10(b)(2)</td>
<td>Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&amp;M, as amended.</td>
<td>Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)</td>
</tr>
<tr>
<td>10(c)</td>
<td>Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&amp;M, KPCo, OPCo and with AEPSC as agent, as amended.</td>
<td>AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525 AEP 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2)</td>
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<td>10(d)(1)</td>
<td>Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&amp;M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.</td>
<td>2004 Form 10-K, Ex 10(d)(1)</td>
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<td>10(d)(2)</td>
<td>PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.</td>
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<td>Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&amp;M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.</td>
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<td>AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525</td>
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<td>Consent Decree with U.S. District Court.</td>
<td>Form 8-K, Ex 10.1 dated October 9, 2007</td>
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<tr>
<td>10(g)</td>
<td>Lease Agreements, dated as of December 1, 1989, between I&amp;M and Wilmington Trust Company, as amended.</td>
<td>Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) 1993 Form 10-K, Ex 10(e)(1-6)(B)</td>
</tr>
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**REGISTRANT: OPCo‡ File No.1-6543**

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<td>3(a)</td>
<td>Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.</td>
<td>Form 10-Q, Ex 3(e), June 30, 2002</td>
</tr>
<tr>
<td>3(b)</td>
<td>Amended Code of Regulations of OPCo.</td>
<td>Form 10-Q, Ex 3(b), June 30, 2008</td>
</tr>
<tr>
<td>4(a)</td>
<td>Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.</td>
<td>Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-75783, Ex 4(b)(c) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(a)(b)(c)</td>
</tr>
<tr>
<td>4(b)</td>
<td>Company Order and Officer’s Certificate to Deutsche Bank Trust Company Americas, dated April 5, 2007, establishing terms of Floating Rate Notes, Series B.</td>
<td>Form 8-K, Ex 4(a) dated April 5, 2007</td>
</tr>
<tr>
<td>4(c)</td>
<td>Company Order and Officer’s Certificate to Deutsche Bank Trust Company Americas, dated September 9, 2008, establishing terms of 5.75% Senior Notes, Series L due 2013.</td>
<td>Form 8-K, Ex 4(a) dated September 9, 2008</td>
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<tr>
<td>4(d)</td>
<td>Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.</td>
<td>Registration Statement No. 333-127913, Ex 4(d)(e)(f)</td>
</tr>
<tr>
<td>4(e)</td>
<td>$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(c) September 30, 2008</td>
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<td>4(f)</td>
<td>Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(d) September 30, 2008</td>
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<td>4(g)</td>
<td>$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPco, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
<td>Form 10-Q, Ex. 10(e) September 30, 2008</td>
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<td>4(h)</td>
<td>Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.</td>
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<td>10(a)(1)</td>
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<td>Registration Statement No. 2-60015, Ex 5(a) &lt;br&gt;Registration Statement No. 2-63234, Ex 5(a)(1)(B) &lt;br&gt;Registration Statement No. 2-66301, Ex 5(a)(1)(C) &lt;br&gt;Registration Statement No. 2-67728, Ex 5(a)(1)(D) &lt;br&gt;APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 &lt;br&gt;APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457</td>
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<td>10(a)(3)</td>
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<td>Registration Statement No. 2-60015, Ex 5(e)</td>
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<tr>
<td>10(b)</td>
<td>Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPco, I&amp;M and OPCo and with AEPSC, as amended.</td>
<td>Registration Statement No. 2-52910, Ex 5(a) &lt;br&gt;Registration Statement No. 2-61009, Ex 5(b) &lt;br&gt;AEP 1990 Form 10-K, Ex 10(a)(3), File 1-3525</td>
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<tr>
<td>10(c)</td>
<td>Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&amp;M, KPco, OPCo and with AEPSC as agent.</td>
<td>AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525 &lt;br&gt;AEP 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525</td>
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<td>10(d)(1)</td>
<td>Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&amp;M, KPco, OPCo, Kingsport Power Company and Wheeling Power Company.</td>
<td>2004 Form 10-K, Ex 10(d)(1)</td>
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<td>10(d)(2)</td>
<td>PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.</td>
<td>2004 Form 10-K, Ex 10(d)(2)</td>
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<td>10(d)(3)</td>
<td>Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&amp;M, KPco, OPCo, Kingsport Power Company and Wheeling Power Company.</td>
<td>2004 Form 10-K, Ex 10(d)(3)</td>
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<td>10(e)</td>
<td>Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&amp;M, KPco, OPCo and AEPSC.</td>
<td>AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525</td>
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<td>10(f)</td>
<td>Consent Decree with U.S. District Court.</td>
<td>Form 8-K, Item Ex 10.1 dated October 9, 2007</td>
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<tr>
<td>10(g)(1)</td>
<td>Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and all amendments thereto.</td>
<td>1993 Form 10-K, Ex 10(f) &lt;br&gt;2003 Form 10-K, Ex 10(e)</td>
</tr>
<tr>
<td>10(g)(2)</td>
<td>Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and all amendments thereto.</td>
<td>Form 10-Q, Ex 10(a), September 30, 2004</td>
</tr>
<tr>
<td>10(h)</td>
<td>Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested).</td>
<td>1994 Form 10-K, Ex 10(l)(2)</td>
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<td>†10(o)(1)</td>
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<td>†10(q)(1)</td>
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<td>AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.</td>
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REGISTRANT:  **PSO**  File No. 0-343

<p>| 3(a) | Certificate of Amendment to Restated Certificate of Incorporation of PSO. | Form 10-Q, Ex 3(a), June 30, 2008 |
| 3(b) | Composite By-Laws of PSO amended as of February 26, 2008. | 2007 Form 10-k, Ex 3 (b) |
| 4(a) | Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee. | Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c) |
| 4(b) | Sixth Supplemental Indenture, dated as of August 10, 2006 between PSO and The Bank of New York, as Trustee, establishing terms of the 6.15% Senior Notes, Series F, due 2016. | Form 8-K, Ex 4(a), dated August 11, 2006 |
| 4(c) | Seventh Supplemental Indenture, dated as of November 14, 2007 between PSO and The Bank of New York, as Trustee, establishing terms of the 6.625% Senior Notes, Series G, due 2037. | Form 8-K, Ex 4(a), dated November 14, 2007 |
| 4(d) | $650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. | Form 10-Q, Ex. 10(c) September 30, 2008 |
| 4(e) | Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent. | Form 10-Q, Ex. 10(d) September 30, 2008 |
| 4(f) | $350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&amp;M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders | Form 10-Q, Ex. 10(e) September 30, 2008 |</p>
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<td>Form 10-Q, Ex. 10(f) September 30, 2008</td>
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<td>10(a)</td>
<td>Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.</td>
<td>Form 10-Q, Ex 10(a), March 31, 2006</td>
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<td>10(b)</td>
<td>Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.</td>
<td>2002 Form 10-K, Ex 10(b)</td>
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<td>†10(i)(1)</td>
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**REGISTRANT: SWEPCo‡ File No. 1-3146**

<p>| 3(a)                | Composite of Amended Restated Certificate of Incorporation of SWEPCo. | 2007 Form 10-K, Ex 3(b) |
| 3(b)                | Composite By-Laws of SWEPCo amended as of February 26, 2008. |                                |
| 4(b)                | Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee. | Registration Statement No. 333-96213 |
| 4(c)                | Sixth Supplemental Indenture, dated as of December 4, 2007 between SWEPCo and The Bank of New York, as Trustee, establishing terms of 5.875% Senior Notes, Series F, due 2018. | Form 8-K, Ex 4(a), dated December 4, 2007 |
| 4(d)                | Seventh Supplemental Indenture, dated as of June 9, 2008 between SWEPCo and The Bank of New York, as Trustee, establishing terms of 5.875% Senior Notes, Series F, due 2018. | Form 8-K, Ex 4(a) dated June 9, 2008 |</p>
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<td>*†10(i)(3)(A)</td>
<td>Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.</td>
<td></td>
</tr>
<tr>
<td>†10(i)(4)</td>
<td>AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2008.</td>
<td></td>
</tr>
<tr>
<td>**†10(j)</td>
<td>Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009</td>
<td></td>
</tr>
<tr>
<td>**†10(k)</td>
<td>AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.</td>
<td></td>
</tr>
<tr>
<td>†10(l)</td>
<td>AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.</td>
<td>2002 Form 10-K, Ex 10(p)</td>
</tr>
<tr>
<td>**†10(m)</td>
<td>Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.</td>
<td></td>
</tr>
<tr>
<td>*12</td>
<td>Statement re: Computation of Ratios.</td>
<td></td>
</tr>
<tr>
<td>*13</td>
<td>Copy of those portions of the SWEPCo 2008 Annual Report (for the fiscal year ended December 31, 2008) which are incorporated by reference in this filing.</td>
<td></td>
</tr>
<tr>
<td>21</td>
<td>List of subsidiaries of SWEPCo.</td>
<td>AEP 2006 Form 10-K, Ex 21, File No. 1-3525</td>
</tr>
<tr>
<td>*23</td>
<td>Consent of Deloitte &amp; Touche LLP.</td>
<td></td>
</tr>
<tr>
<td>*24</td>
<td>Power of Attorney.</td>
<td></td>
</tr>
<tr>
<td>*31(a)</td>
<td>Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</td>
<td></td>
</tr>
<tr>
<td>*31(b)</td>
<td>Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</td>
<td></td>
</tr>
<tr>
<td>*32(a)</td>
<td>Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.</td>
<td></td>
</tr>
<tr>
<td>*32(b)</td>
<td>Certification of Chief Financial Officer Pursuant to</td>
<td></td>
</tr>
<tr>
<td>Exhibit Designation</td>
<td>Nature of Exhibit</td>
<td>Previously Filed as Exhibit to:</td>
</tr>
<tr>
<td>--------------------</td>
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<td>-------------------------------</td>
</tr>
<tr>
<td></td>
<td>Section 1350 of Chapter 63 of Title 18 of the United States Code.</td>
<td></td>
</tr>
</tbody>
</table>

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.
2008 Annual Reports

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Appalachian Power Company and Subsidiaries
Columbus Southern Power Company and Subsidiaries
Indiana Michigan Power Company and Subsidiaries
Ohio Power Company Consolidated
Public Service Company of Oklahoma
Southwestern Electric Power Company Consolidated

Audited Financial Statements and
Management’s Financial Discussion and Analysis

AEP
AMERICAN ELECTRIC POWER
AEP, America’s Energy Partner®
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Forward-Looking Information

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- Selected Consolidated Financial Data B-1
- Management’s Financial Discussion and Analysis B-2
- Quantitative and Qualitative Disclosures About Risk Management Activities B-11
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- Quantitative and Qualitative Disclosures About Risk Management Activities C-4
- Consolidated Financial Statements C-5
- Index to Notes to Financial Statements of Registrant Subsidiaries C-10
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- Management’s Narrative Financial Discussion and Analysis D-1
- Quantitative and Qualitative Disclosures About Risk Management Activities D-4
- Consolidated Financial Statements D-5
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- Quantitative and Qualitative Disclosures About Risk Management Activities E-11
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- Selected Financial Data: F-1
- Management’s Financial Discussion and Analysis: F-2
- Quantitative and Qualitative Disclosures About Risk Management Activities: F-10
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- Management’s Financial Discussion and Analysis: G-2
- Quantitative and Qualitative Disclosures About Risk Management Activities: G-11
- Consolidated Financial Statements: G-15
- Index to Notes to Financial Statements of Registrant Subsidiaries: G-20
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# Glossary of Terms

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

<table>
<thead>
<tr>
<th>Term</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEGCo</td>
<td>AEP Generating Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>AEP or Parent</td>
<td>American Electric Power Company, Inc.</td>
</tr>
<tr>
<td>AEP Consolidated</td>
<td>AEP and its majority owned consolidated subsidiaries and consolidated affiliates.</td>
</tr>
<tr>
<td>AEP Credit</td>
<td>AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.</td>
</tr>
<tr>
<td>AEP East companies</td>
<td>APCo, CSPCo, I&amp;M, KPCo and OPCo.</td>
</tr>
<tr>
<td>AEP Foundation</td>
<td>AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP’s subsidiaries operate.</td>
</tr>
<tr>
<td>AEP Power Pool</td>
<td>Members are APCo, CSPCo, I&amp;M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.</td>
</tr>
<tr>
<td>AEP System or the System</td>
<td>American Electric Power System, an integrated electric utility system, owned and operated by AEP’s electric utility subsidiaries.</td>
</tr>
<tr>
<td>AEP West companies</td>
<td>PSO, SWEPCo, TCC and TNC.</td>
</tr>
<tr>
<td>AEPEP</td>
<td>AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.</td>
</tr>
<tr>
<td>AEPES</td>
<td>AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.</td>
</tr>
<tr>
<td>AEPSC</td>
<td>American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.</td>
</tr>
<tr>
<td>AFUDC</td>
<td>Allowance for Funds Used During Construction.</td>
</tr>
<tr>
<td>ALJ</td>
<td>Administrative Law Judge.</td>
</tr>
<tr>
<td>AOCI</td>
<td>Accumulated Other Comprehensive Income.</td>
</tr>
<tr>
<td>APCo</td>
<td>Appalachian Power Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>APSC</td>
<td>Arkansas Public Service Commission.</td>
</tr>
<tr>
<td>ARO</td>
<td>Asset Retirement Obligations.</td>
</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act.</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide.</td>
</tr>
<tr>
<td>Cook Plant</td>
<td>Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&amp;M.</td>
</tr>
<tr>
<td>CSPCo</td>
<td>Columbus Southern Power Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>CSW</td>
<td>Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).</td>
</tr>
<tr>
<td>CSW Operating Agreement</td>
<td>Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.</td>
</tr>
<tr>
<td>CTC</td>
<td>Competition Transition Charge.</td>
</tr>
<tr>
<td>CWIP</td>
<td>Construction Work in Progress.</td>
</tr>
<tr>
<td>DETM</td>
<td>Duke Energy Trading and Marketing L.L.C., a risk management counterparty.</td>
</tr>
<tr>
<td>DHLLC</td>
<td>Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo that is consolidated under FIN 46R.</td>
</tr>
<tr>
<td>DOE</td>
<td>United States Department of Energy.</td>
</tr>
<tr>
<td>DOJ</td>
<td>United States Department of Justice.</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand-side Management.</td>
</tr>
<tr>
<td>E&amp;R</td>
<td>Environmental compliance and transmission and distribution system reliability.</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>Term</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>EaR</td>
<td>Earnings at Risk, a method to quantify risk exposure.</td>
</tr>
<tr>
<td>EIS</td>
<td>Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates under FIN 46R.</td>
</tr>
<tr>
<td>EITF 06-10</td>
<td>EITF Issue No. 06-10 “Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements.”</td>
</tr>
<tr>
<td>EPS</td>
<td>Earnings Per Share.</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Electric Reliability Council of Texas.</td>
</tr>
<tr>
<td>ETA</td>
<td>Electric Transmission America, LLC a 50% equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in North America outside of ERCOT.</td>
</tr>
<tr>
<td>ETT</td>
<td>Electric Transmission Texas, LLC, a 50% equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in ERCOT.</td>
</tr>
<tr>
<td>FASB</td>
<td>Financial Accounting Standards Board.</td>
</tr>
<tr>
<td>Federal EPA</td>
<td>United States Environmental Protection Agency.</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission.</td>
</tr>
<tr>
<td>FGD</td>
<td>Flue Gas Desulfurization or Scrubbers.</td>
</tr>
<tr>
<td>FIN</td>
<td>FASB Interpretation No.</td>
</tr>
<tr>
<td>FIN 46R</td>
<td>FIN 46R, “Consolidation of Variable Interest Entities.”</td>
</tr>
<tr>
<td>FIN 48</td>
<td>FIN 48, “Accounting for Uncertainty in Income Taxes” and FASB Staff Position FIN 48-1 “Definition of Settlement in FASB Interpretation No. 48.”</td>
</tr>
<tr>
<td>FSP</td>
<td>FASB Staff Position.</td>
</tr>
<tr>
<td>FSP FIN 39-1</td>
<td>FSP FIN 39-1, “Amendment of FASB Interpretation No. 39.”</td>
</tr>
<tr>
<td>FTR</td>
<td>Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.</td>
</tr>
<tr>
<td>GAAP</td>
<td>Accounting Principles Generally Accepted in the United States of America.</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gases.</td>
</tr>
<tr>
<td>HPL</td>
<td>Houston Pipeline Company, a former AEP subsidiary.</td>
</tr>
<tr>
<td>IGCC</td>
<td>Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.</td>
</tr>
<tr>
<td>Interconnection Agreement</td>
<td>Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&amp;M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.</td>
</tr>
<tr>
<td>IRS</td>
<td>Internal Revenue Service.</td>
</tr>
<tr>
<td>IURC</td>
<td>Indiana Utility Regulatory Commission.</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>Indiana Michigan Power Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>JMG</td>
<td>JMG Funding LP, a financing company that OPCo consolidates under FIN 46R.</td>
</tr>
<tr>
<td>KGPCo</td>
<td>Kingsport Power Company, an AEP electric distribution subsidiary.</td>
</tr>
<tr>
<td>KPCo</td>
<td>Kentucky Power Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>KPSC</td>
<td>Kentucky Public Service Commission.</td>
</tr>
<tr>
<td>KV</td>
<td>Kilovolt.</td>
</tr>
<tr>
<td>KWH</td>
<td>Kilowatthour.</td>
</tr>
<tr>
<td>LPSC</td>
<td>Louisiana Public Service Commission.</td>
</tr>
<tr>
<td>Term</td>
<td>Meaning</td>
</tr>
<tr>
<td>---------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>MISO</td>
<td>Midwest Independent Transmission System Operator.</td>
</tr>
<tr>
<td>MLR</td>
<td>Member load ratio, the method used to allocate AEP Power Pool transactions to its members.</td>
</tr>
<tr>
<td>MPSC</td>
<td>Michigan Public Service Commission.</td>
</tr>
<tr>
<td>MTM</td>
<td>Mark-to-Market.</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt.</td>
</tr>
<tr>
<td>MWH</td>
<td>Megawatthour.</td>
</tr>
<tr>
<td>NOx</td>
<td>Nitrogen oxide.</td>
</tr>
<tr>
<td>Nonutility Money Pool</td>
<td>AEP System’s Nonutility Money Pool.</td>
</tr>
<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission.</td>
</tr>
<tr>
<td>NSR</td>
<td>New Source Review.</td>
</tr>
<tr>
<td>OATT</td>
<td>Open Access Transmission Tariff.</td>
</tr>
<tr>
<td>OCC</td>
<td>Corporation Commission of the State of Oklahoma.</td>
</tr>
<tr>
<td>OPCo</td>
<td>Ohio Power Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>OPEB</td>
<td>Other Postretirement Benefit Plans.</td>
</tr>
<tr>
<td>OTC</td>
<td>Over the counter.</td>
</tr>
<tr>
<td>OVEC</td>
<td>Ohio Valley Electric Corporation, which is 43.47% owned by AEP.</td>
</tr>
<tr>
<td>PATH</td>
<td>Potomac Appalachian Transmission Highline, LLC and its subsidiaries, a joint venture with Allegheny Energy Inc. formed to own and operate electric transmission facilities in PJM.</td>
</tr>
<tr>
<td>PJM</td>
<td>Pennsylvania – New Jersey – Maryland regional transmission organization.</td>
</tr>
<tr>
<td>PM</td>
<td>Particulate Matter.</td>
</tr>
<tr>
<td>PSO</td>
<td>Public Service Company of Oklahoma, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>PUCO</td>
<td>Public Utilities Commission of Ohio.</td>
</tr>
<tr>
<td>PUCT</td>
<td>Public Utility Commission of Texas.</td>
</tr>
<tr>
<td>Registrant Subsidiaries</td>
<td>AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&amp;M, OPCo, PSO and SWEPCo.</td>
</tr>
<tr>
<td>REP</td>
<td>Texas Retail Electric Provider.</td>
</tr>
<tr>
<td>Risk Management Contracts</td>
<td>Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.</td>
</tr>
<tr>
<td>Rockport Plant</td>
<td>A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&amp;M.</td>
</tr>
<tr>
<td>RSP</td>
<td>Rate Stabilization Plan.</td>
</tr>
<tr>
<td>RTO</td>
<td>Regional Transmission Organization.</td>
</tr>
<tr>
<td>S&amp;P</td>
<td>Standard and Poor’s.</td>
</tr>
<tr>
<td>Sabine</td>
<td>Sabine Mining Company, a lignite mining company that SWEPCo consolidates under FIN 46R.</td>
</tr>
<tr>
<td>SCR</td>
<td>Selective Catalytic Reduction.</td>
</tr>
<tr>
<td>SEC</td>
<td>United States Securities and Exchange Commission.</td>
</tr>
<tr>
<td>SECA</td>
<td>Seams Elimination Cost Allocation.</td>
</tr>
<tr>
<td>Term</td>
<td>Meaning</td>
</tr>
<tr>
<td>------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>SIA</td>
<td>System Integration Agreement.</td>
</tr>
<tr>
<td>SNF</td>
<td>Spent Nuclear Fuel.</td>
</tr>
<tr>
<td>SO₂</td>
<td>Sulfur Dioxide.</td>
</tr>
<tr>
<td>SPP</td>
<td>Southwest Power Pool.</td>
</tr>
<tr>
<td>Stall Unit</td>
<td>J. Lamar Stall Unit at Arsenal Hill Plant.</td>
</tr>
<tr>
<td>Sweeny</td>
<td>Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Southwestern Electric Power Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>TCC</td>
<td>AEP Texas Central Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>TCRR</td>
<td>Transmission Cost Recovery Rider.</td>
</tr>
<tr>
<td>TEM</td>
<td>SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).</td>
</tr>
<tr>
<td>Texas Restructuring Legislation</td>
<td>Legislation enacted in 1999 to restructure the electric utility industry in Texas.</td>
</tr>
<tr>
<td>TNC</td>
<td>AEP Texas North Company, an AEP electric utility subsidiary.</td>
</tr>
<tr>
<td>True-up Proceeding</td>
<td>A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.</td>
</tr>
<tr>
<td>Turk Plant</td>
<td>John W. Turk, Jr. Plant.</td>
</tr>
<tr>
<td>VaR</td>
<td>Value at Risk, a method to quantify risk exposure.</td>
</tr>
<tr>
<td>Virginia SCC</td>
<td>Virginia State Corporation Commission.</td>
</tr>
<tr>
<td>WPCo</td>
<td>Wheeling Power Company, an AEP electric distribution subsidiary.</td>
</tr>
<tr>
<td>WVPSC</td>
<td>Public Service Commission of West Virginia.</td>
</tr>
</tbody>
</table>
FORWARD-LOOKING INFORMATION

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

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- 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 including our ability to restore Cook Plant Unit 1 in a timely manner.
- 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 and transmission line facilities (including our ability to obtain any necessary regulatory or siting approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) 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.
- 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 markets.
- 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 implementation of the recently passed utility law in Ohio and the allocation of costs within RTOs, including PJM and SPP.
- 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 and the impact on future funding requirements.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.
AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

<table>
<thead>
<tr>
<th>Quarter Ended</th>
<th>High</th>
<th>Low</th>
<th>Quarter-End Closing Price</th>
<th>Dividend</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 31, 2008</td>
<td>$37.28</td>
<td>$25.54</td>
<td>$33.28</td>
<td>$0.41</td>
</tr>
<tr>
<td>September 30, 2008</td>
<td>41.60</td>
<td>34.86</td>
<td>37.03</td>
<td>0.41</td>
</tr>
<tr>
<td>June 30, 2008</td>
<td>45.95</td>
<td>39.46</td>
<td>40.23</td>
<td>0.41</td>
</tr>
<tr>
<td>March 31, 2008</td>
<td>49.11</td>
<td>39.35</td>
<td>41.63</td>
<td>0.41</td>
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<tr>
<td>December 31, 2007</td>
<td>$49.49</td>
<td>$45.05</td>
<td>$46.56</td>
<td>$0.41</td>
</tr>
<tr>
<td>September 30, 2007</td>
<td>48.83</td>
<td>42.46</td>
<td>46.08</td>
<td>0.39</td>
</tr>
<tr>
<td>June 30, 2007</td>
<td>51.24</td>
<td>43.39</td>
<td>45.04</td>
<td>0.39</td>
</tr>
<tr>
<td>March 31, 2007</td>
<td>49.47</td>
<td>41.67</td>
<td>48.75</td>
<td>0.39</td>
</tr>
</tbody>
</table>

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2008, AEP had approximately 100,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

* $100 invested on 12/31/03 in stock & index-including reinvestment of dividends.
Fiscal year ending December 31.

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## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

### SELECTED CONSOLIDATED FINANCIAL DATA

#### STATEMENTS OF INCOME DATA

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Revenues</strong></td>
<td>$14,440</td>
<td>$13,380</td>
<td>$12,622</td>
<td>$12,111</td>
<td>$14,245</td>
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<tr>
<td><strong>Operating Income</strong></td>
<td>$2,787</td>
<td>$2,319</td>
<td>$1,966</td>
<td>$1,927</td>
<td>$1,983</td>
</tr>
<tr>
<td><strong>Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change</strong></td>
<td>$1,368</td>
<td>$1,144</td>
<td>$992</td>
<td>$1,029</td>
<td>$1,127</td>
</tr>
<tr>
<td><strong>Discontinued Operations, Net of Tax</strong></td>
<td>-</td>
<td>12</td>
<td>24</td>
<td>10</td>
<td>27</td>
</tr>
<tr>
<td><strong>Income Before Extraordinary Loss and Cumulative Effect of Accounting Change</strong></td>
<td>1,380</td>
<td>1,168</td>
<td>1,002</td>
<td>1,056</td>
<td>1,210</td>
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<tr>
<td><strong>Extraordinary Loss, Net of Tax</strong></td>
<td>-</td>
<td>(79)</td>
<td>-</td>
<td>(225)(a)</td>
<td>(121)</td>
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<tr>
<td><strong>Cumulative Effect of Accounting Change, Net of Tax</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(17)</td>
<td>-</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>$1,380</td>
<td>$1,089</td>
<td>$1,002</td>
<td>$814</td>
<td>$1,089</td>
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#### BALANCE SHEETS DATA

<table>
<thead>
<tr>
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<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Property, Plant and Equipment</strong></td>
<td>$49,710</td>
<td>$46,145</td>
<td>$42,021</td>
<td>$39,121</td>
<td>$37,294</td>
</tr>
<tr>
<td><strong>Accumulated Depreciation and Amortization</strong></td>
<td>$16,723</td>
<td>$16,275</td>
<td>$15,240</td>
<td>$14,837</td>
<td>$14,493</td>
</tr>
<tr>
<td><strong>Net Property, Plant and Equipment</strong></td>
<td>$32,987</td>
<td>$29,870</td>
<td>$26,781</td>
<td>$24,284</td>
<td>$22,801</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$45,155</td>
<td>$40,319 (b)</td>
<td>$37,877 (b)</td>
<td>$35,662 (b)</td>
<td>$34,388 (b)</td>
</tr>
<tr>
<td><strong>Common Shareholders’ Equity</strong></td>
<td>$10,693</td>
<td>$10,079</td>
<td>$9,412</td>
<td>$9,088</td>
<td>$8,515</td>
</tr>
<tr>
<td><strong>Cumulative Preferred Stocks of Subsidiaries</strong></td>
<td>$61</td>
<td>$61</td>
<td>$61</td>
<td>$61</td>
<td>$127</td>
</tr>
<tr>
<td><strong>Long-term Debt (c)</strong></td>
<td>$15,983</td>
<td>$14,994</td>
<td>$13,698</td>
<td>$12,226</td>
<td>$12,287</td>
</tr>
<tr>
<td><strong>Obligations Under Capital Leases (c)</strong></td>
<td>$325</td>
<td>$371</td>
<td>$291</td>
<td>$251</td>
<td>$243</td>
</tr>
</tbody>
</table>

#### COMMON STOCK DATA

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Basic Earnings (Loss) per Common Share:</strong></td>
<td>$3.40</td>
<td>$2.87</td>
<td>$2.52</td>
<td>$2.64</td>
<td>$2.85</td>
</tr>
<tr>
<td><strong>Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Discontinued Operations, Net of Tax</strong></td>
<td>0.03</td>
<td>0.06</td>
<td>0.02</td>
<td>0.07</td>
<td>0.21</td>
</tr>
<tr>
<td><strong>Income Before Extraordinary Loss and Cumulative Effect of Accounting Change</strong></td>
<td>3.43</td>
<td>2.93</td>
<td>2.54</td>
<td>2.71</td>
<td>3.06</td>
</tr>
<tr>
<td><strong>Extraordinary Loss, Net of Tax</strong></td>
<td>-</td>
<td>(0.20)</td>
<td>-</td>
<td>(0.58)</td>
<td>(0.31)</td>
</tr>
<tr>
<td><strong>Cumulative Effect of Accounting Change, Net of Tax</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(0.04)</td>
<td>-</td>
</tr>
<tr>
<td><strong>Basic Earnings Per Share</strong></td>
<td>$3.43</td>
<td>$2.73</td>
<td>$2.54</td>
<td>$2.09</td>
<td>$2.75</td>
</tr>
</tbody>
</table>

- **Basic Earnings Per Share**
  - 2008: $3.43
  - 2007: $2.73
  - 2006: $2.54
  - 2005: $2.09
  - 2004: $2.75

- **Weighted Average Number of Basic Shares Outstanding**
  - 2008: 402
  - 2007: 399
  - 2006: 394
  - 2005: 390
  - 2004: 396

- **Market Price Range**
  - **High**: $49.11
  - **Low**: $25.54

- **Year-end Market Price**: $33.28

- **Cash Dividends Paid per Common Share**: $1.64

- **Dividend Payout Ratio**: 47.8%

- **Book Value per Share**: $26.35

---

(a) Extraordinary Loss, Net of Tax for 2005 reflects TCC’s stranded cost.
(b) Includes reclassification of assets due to FSP FIN 39-1 adoption effective in 2008. See “FSP FIN 39-1” section of Note 2.
(c) Includes portion due within one year.
American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We operate an extensive portfolio of assets including:

- Almost 39,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most of our market areas.
- Approximately 39,000 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 distribution lines that deliver electricity to 5.2 million customers.
- Substantial commodity transportation assets (more than 9,000 railcars, 2,978 barges, 58 towboats, 25 harbor boats and a coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

OUTLOOK FOR 2009

We remain focused on the fundamental earning power of our utilities and are committed to maintaining our credit quality and liquidity. To achieve our goals we plan to:

- Hold operation and maintenance expense relatively flat as compared to 2008.
- Significantly reduce our capital expenditures while continuing construction of additional new generation.
- Aggressively seek rate relief by developing rate plans that obtain favorable and timely resolutions to our rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.

There are, nevertheless, certain risks and challenges that must be overcome including:

- Domestic and international economic slowdowns.
- Access to capital markets to support our proposed capital expenditures.
- Intervention by consumer advocates in current and future state and FERC regulatory proceedings who try to keep rates down at the expense of a fair return.
- Wholesale market volatility.
- The return to service of Cook Plant Unit 1 and overall plant availability.
- Managing our overall generating fleet to maximize our off-system sales opportunities despite the loss of production from Cook Plant Unit 1.
- Fuel cost volatility and timely fuel cost recovery, including related transportation costs.
- Managing the effects of potential environmental legislation and regulation regarding carbon dioxide and other emissions on our existing generating fleet.
- Expanding our generating fleet while complying with potential new emission restrictions on the construction of future plants.
- Weather-related system reliability and utilization.
Regulatory Activity

In 2009, our significant regulatory activities will include:

- Achieving favorable regulatory results in Ohio under Senate Bill 221.
- Maintaining adequate returns in AEP’s retail jurisdictions by filing for rate increases, where necessary.
- Continuing progress on major transmission projects by:
  - Securing favorable regulatory treatment for transmission projects.
  - Obtaining successful outcomes in siting and right of way filings.
  - Seeking proper cost recovery within and across RTOs.

Capital Markets

As a result of domestic and world economic slowdowns in 2008, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting our access to capital, liquidity, asset valuations in our trust funds, the creditworthy status of customers, suppliers and trading partners and our cost of capital. Our financial staff actively manages these factors with oversight from our risk committee. The uncertainties in the capital markets could have significant implications since we rely on continuing access to capital to fund operations and capital expenditures.

The current credit markets are constraining our ability to issue new debt, including commercial paper, and to refinance existing debt. We cannot predict the length of time the current capital market situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates. If market conditions improve, we plan to repay portions of the amounts drawn under the credit facilities and issue commercial paper and long-term debt.

We believe that we have adequate liquidity to support our planned business operations and construction program through 2009 due to the following:

- We have $1.9 billion in aggregate available credit facility commitments as of December 31, 2008. These commitments include 27 different banks with no one bank having more than 10% of our total bank commitments. In April 2009, $338 million of our $1.9 billion in available credit facility commitments will expire. As of December 31, 2008, our total cash and cash equivalents were $411 million.
- Of our $16 billion of long-term debt as of December 31, 2008, approximately $300 million will mature in 2009 (approximately 1.9% of our outstanding long-term debt as of December 31, 2008). We intend to refinance these maturities. The $300 million of 2009 maturities exclude payments due for securitization bonds which we recover directly from ratepayers.
- We will receive a favorable impact in 2009 due to base rate increases in Oklahoma and Virginia and an expected base rate increase in Indiana. We are currently awaiting a decision on the Ohio ESP filings.
- We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations.

Approximately $1.5 billion of outstanding long-term debt will mature in 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. In conjunction with the upcoming resolution of the Ohio ESPs, we will be reevaluating our operating and financial plans and those plans could possibly include debt and/or equity issuances.

We have significant investments in several trust funds to provide for future payments of pensions, OPEB, nuclear decommissioning and spent nuclear fuel disposal. Although all of our trust funds’ investments are diversified and managed in compliance with all laws and regulations, the value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds’ ability to make their required payments. As of December 31, 2008, the decline in pension asset values will not require us to make a contribution under ERISA in 2009. We currently estimate that we will need to make minimum contributions to our pension trust of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.
We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. Our risk management organization monitors these exposures on a daily basis to limit our economic and financial statement impact on a counterparty basis. At December 31, 2008, our credit exposure net of collateral was approximately $764 million of which approximately 92% is to investment grade counterparties. At December 31, 2008, our exposure to financial institutions was $80 million, which represents 11% of our total credit exposure net of collateral (all investment grade).

**Economic Slowdown**

Following the indications of a slowing economy in 2007, the U.S. economy experienced what some have labeled a financial crisis in 2008. These economic troubles impacted and will continue to impact our residential, commercial and industrial sales as well as sales opportunities in the wholesale market. Most sections of our service territories are experiencing slowdowns in new construction, resulting in our residential and commercial customer base growing at a decreased rate. Starting in the fourth quarter of 2008, various sections of our service territories also experienced decreases in industrial sales due to temporary shutdowns and reduced shifts by some of our large industrial customers. We expect these trends to continue throughout 2009.

**Capital Expenditures**

Due to recent capital market instability and the economic slowdown, we reduced our planned capital expenditures for 2009 by $750 million:

<table>
<thead>
<tr>
<th>Capital Expenditure</th>
<th>Original 2009 Projection</th>
<th>Revised 2009 Budget Reduction</th>
<th>Revised 2009 Capital Expenditure Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Generation</td>
<td>$469</td>
<td>$234</td>
<td>235</td>
</tr>
<tr>
<td>Environmental</td>
<td>668</td>
<td>(232)</td>
<td>436</td>
</tr>
<tr>
<td>Other Generation</td>
<td>643</td>
<td>(37)</td>
<td>606</td>
</tr>
<tr>
<td>Transmission</td>
<td>476</td>
<td>56</td>
<td>532</td>
</tr>
<tr>
<td>Distribution</td>
<td>949</td>
<td>(263)</td>
<td>686</td>
</tr>
<tr>
<td>Corporate</td>
<td>129</td>
<td>(40)</td>
<td>89</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,334</strong></td>
<td><strong>750</strong></td>
<td><strong>2,584</strong></td>
</tr>
</tbody>
</table>

The reduction in capital spending will reduce our need to access the capital markets in 2009. While many of these cutbacks involve the delay of certain capital projects into future years, these reductions will not jeopardize the reliability of the AEP System. Projected capital expenditures for 2010 are currently under review.

**Cook Plant Unit 1 Fire and Shutdown**

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. Our current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.
Fuel Costs

Coal prices increased by approximately 29% in 2008 due to several factors including escalating market prices and increased demand, primarily in our eastern region as a result of the expiration of lower-priced coal and transportation contracts being replaced with higher-priced contracts. During 2008, we had price risk exposure in Ohio, representing approximately 20% of our fuel costs. For 2009, we expect our coal costs to increase by approximately 15%. We have active fuel cost recovery mechanisms in all of our jurisdictions except Ohio. We expect the PUCO to reinstate a fuel cost recovery mechanism. An order on the ESPs is expected before the end of the first quarter of 2009. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009.

2008 RESULTS

We had many accomplishments in 2008, including strong earnings despite the economic climate. Our earnings per-share increased in 2008 to $3.43 per share. We completed construction of new generating units at our Southwestern Station and Riverside Station in Oklahoma and continued construction of the Stall Unit, Turk Plant and Dresden Plant generating facilities in Louisiana, Arkansas and Ohio, respectively. We also continued our pursuit of joint venture opportunities to invest in transmission facilities in PJM, ERCOT and other regions.
RESULTS OF OPERATIONS

Segments

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

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

AEP River Operations
- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 13% for steel and 19% for other commodities. Effective July 30, 2008, AEP MEMCO LLC’s name was changed to AEP River Operations LLC.

Generation and Marketing
- Wind farms and marketing and risk management activities primarily in ERCOT. Our 50% interest in Sweeny Cogeneration Plant was sold in October 2007. See “Sweeny Cogeneration Plant” section of Note 7.


<table>
<thead>
<tr>
<th>Segment</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Operations</td>
<td>$1,115</td>
<td>$1,031</td>
<td>$1,028</td>
</tr>
<tr>
<td>AEP River Operations</td>
<td>55</td>
<td>61</td>
<td>80</td>
</tr>
<tr>
<td>Generation and Marketing</td>
<td>65</td>
<td>67</td>
<td>12</td>
</tr>
<tr>
<td>All Other (a)</td>
<td>133</td>
<td>(15)</td>
<td>(128)</td>
</tr>
<tr>
<td>Income Before Discontinued Operations and Extraordinary Loss</td>
<td>$1,368</td>
<td>$1,144</td>
<td>$992</td>
</tr>
</tbody>
</table>

(a) All Other includes:
- Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See “Plaquemine Cogeneration Facility” section of Note 7.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.
AEP Consolidated

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $224 million compared to 2007 primarily due to income from the cash settlement received in 2008 related to a disputed purchase power and sale agreement with TEM, the 2008 deferral of Oklahoma ice storm expenses incurred in 2007 and base rate increases in our Ohio, Texas and Virginia service territories. These increases over 2007 were partially offset by higher interest expense and fuel expense and a provision for refund recorded to reflect the impact of an order issued in November 2008 by the FERC regarding the affiliate allocation of off-system sales margins under the SIA and the CSW Operating Agreement.

Average basic shares outstanding increased to 402 million in 2008 from 399 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 406 million as of December 31, 2008. In 2008, we contributed 1,250,000 shares of common stock held in treasury to the AEP Foundation.

2007 Compared to 2006

Income Before Discontinued Operations and Extraordinary Loss in 2007 increased $152 million compared to 2006 primarily due to a $136 million after-tax impairment recorded in 2006 related to the sale of the Plaquemine Cogeneration Facility. Despite retail rate increases implemented in Ohio, Kentucky, Oklahoma, Texas, Virginia and West Virginia and favorable weather, Utility Operations earnings were essentially flat due to increases in interest expense, operation and maintenance expenses related to storm restoration in Oklahoma and the NSR settlement.

Average basic shares outstanding increased to 399 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 400 million as of December 31, 2007.

Our results of operations are discussed below by operating segment.

Utility Operations

Our Utility Operations segment includes primarily regulated revenues with direct and variable offsetting expenses and net reported commodity trading operations. We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in millions)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$13,566</td>
<td>$12,655</td>
<td>$12,011</td>
</tr>
<tr>
<td>Fuel and Purchased Power</td>
<td>5,622</td>
<td>4,838</td>
<td>4,669</td>
</tr>
<tr>
<td><strong>Gross Margin</strong></td>
<td>7,944</td>
<td>7,817</td>
<td>7,342</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>1,450</td>
<td>1,483</td>
<td>1,435</td>
</tr>
<tr>
<td>Other Operating Expenses</td>
<td>4,114</td>
<td>4,129</td>
<td>3,843</td>
</tr>
<tr>
<td><strong>Operating Income</strong></td>
<td>2,380</td>
<td>2,205</td>
<td>2,064</td>
</tr>
<tr>
<td>Other Income, Net</td>
<td>169</td>
<td>102</td>
<td>177</td>
</tr>
<tr>
<td>Interest Expense and Preferred Stock Dividend Requirements</td>
<td>919</td>
<td>790</td>
<td>670</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>515</td>
<td>486</td>
<td>543</td>
</tr>
<tr>
<td><strong>Income Before Discontinued Operations and Extraordinary Loss</strong></td>
<td>$1,115</td>
<td>$1,031</td>
<td>$1,028</td>
</tr>
</tbody>
</table>
Summary of KWH Energy Sales for Utility Operations  
For the Years Ended December 31, 2008, 2007 and 2006

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions of KWH)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Retail:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>49,011</td>
<td>49,176</td>
<td>47,222</td>
</tr>
<tr>
<td>Commercial</td>
<td>40,078</td>
<td>40,545</td>
<td>38,579</td>
</tr>
<tr>
<td>Industrial</td>
<td>58,170</td>
<td>57,566</td>
<td>53,914</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>2,501</td>
<td>2,565</td>
<td>2,653</td>
</tr>
<tr>
<td>Total Retail</td>
<td>149,760</td>
<td>149,852</td>
<td>142,368</td>
</tr>
<tr>
<td>Wholesale</td>
<td>42,830</td>
<td>42,917</td>
<td>44,564</td>
</tr>
<tr>
<td>Texas Wires – Energy delivered to customers served by TNC and TCC in ERCOT</td>
<td>27,075</td>
<td>26,682</td>
<td>26,382</td>
</tr>
<tr>
<td>Total KWHs</td>
<td>219,665</td>
<td>219,451</td>
<td>213,314</td>
</tr>
</tbody>
</table>

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations  
For the Years Ended December 31, 2008, 2007 and 2006

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in degree days)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eastern Region</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Actual – Heating (a)</td>
<td>3,148</td>
<td>3,014</td>
<td>2,477</td>
</tr>
<tr>
<td>Normal – Heating (b)</td>
<td>3,018</td>
<td>3,042</td>
<td>3,078</td>
</tr>
<tr>
<td>Actual – Cooling (c)</td>
<td>936</td>
<td>1,266</td>
<td>923</td>
</tr>
<tr>
<td>Normal – Cooling (b)</td>
<td>986</td>
<td>978</td>
<td>985</td>
</tr>
<tr>
<td>Western Region (d)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Actual – Heating (a)</td>
<td>1,613</td>
<td>1,559</td>
<td>1,172</td>
</tr>
<tr>
<td>Normal – Heating (b)</td>
<td>1,561</td>
<td>1,588</td>
<td>1,605</td>
</tr>
<tr>
<td>Actual – Cooling (c)</td>
<td>2,011</td>
<td>2,244</td>
<td>2,430</td>
</tr>
<tr>
<td>Normal – Cooling (b)</td>
<td>2,173</td>
<td>2,181</td>
<td>2,175</td>
</tr>
</tbody>
</table>

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.  
(b) Normal Heating/Cooling represents the thirty-year average of degree days.  
(c) Eastern Region and Western Region cooling degree days are calculated on a 65 degree temperature base.  
(d) Western Region statistics represent PSO/SWEPCo customer base only.
## Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008
### Income from Utility Operations Before Discontinued Operations and Extraordinary Loss

(in millions)

<table>
<thead>
<tr>
<th>Year Ended December 31, 2007</th>
<th>$ 1,031</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Changes in Gross Margin:</strong></td>
<td></td>
</tr>
<tr>
<td>Retail Margins</td>
<td>114</td>
</tr>
<tr>
<td>Off-system Sales</td>
<td>(45)</td>
</tr>
<tr>
<td>Transmission Revenues</td>
<td>33</td>
</tr>
<tr>
<td>Other</td>
<td>25</td>
</tr>
<tr>
<td><strong>Total Change in Gross Margin</strong></td>
<td>127</td>
</tr>
</tbody>
</table>

| **Changes in Operating Expenses and Other:** |        |
| Other Operation and Maintenance | 35 |
| Gain on Dispositions of Assets, Net | (19) |
| Depreciation and Amortization | 33 |
| Taxes Other Than Income Taxes | (1) |
| Interest Income | 21 |
| Carrying Costs Income | 32 |
| Other Income, Net | 14 |
| Interest Expense | (129) |
| **Total Change in Operating Expenses and Other** | (14) |
| Income Tax Expense | (29) |
| **Year Ended December 31, 2008** | $ 1,115 |

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $84 million to $1,115 million in 2008. The key drivers of the increase were a $127 million increase in Gross Margin offset by a $14 million increase in Operating Expenses and Other and a $29 million increase in Income Tax Expense.

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

- Retail Margins increased $114 million primarily due to the following:
  - A $206 million increase related to net rate increases implemented in our Ohio jurisdictions, a $53 million increase related to recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $25 million net increase in rates in Oklahoma, a $21 million increase in base rates in Texas and an $18 million increase in base rates in Virginia.
  - A $99 million net increase due to adjustments recorded in 2007 related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  - A $50 million increase related to increased usage by Ormet, an industrial customer in Ohio. See “Ormet” section of Note 4.
  - A $40 million net increase due to coal contract amendments in 2008.
  - An $18 million decrease in the sharing of off-system sales margins with customers due to a decrease in total off-system sales.
  - A $17 million increase due to a 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.

These increases were partially offset by:

- A $213 million increase in fuel and consumable expenses in Ohio. CSPCo and OPCo have applied for an active fuel clause in their Ohio Electric Security Plan filings to be effective January 1, 2009.
- A $102 million decrease due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
- A $65 million decrease in usage primarily due to a 26% decrease in cooling degree days in our eastern region and a 10% decrease in cooling degree days in our western region.
A $40 million net decrease in retail sales primarily due to lower industrial sales in Indiana, Ohio and Virginia as a result of the economic slowdown in the second half of 2008.

Margins from Off-system Sales decreased $45 million primarily due to higher trading margins realized in 2007 and the favorable effects of a fuel reconciliation in our western service territory in 2007. This decrease was partially offset by higher physical off-system sales in our eastern territory as the result of higher realized prices and higher PJM capacity revenues.

Transmission Revenues increased $33 million primarily due to increased rates.

Other Revenues increased $25 million primarily due to increased third-party engineering and construction work, an increase in pole attachment revenue and an unfavorable provision for TCC for the refund of bonded rates recorded in 2007.

Utility Operating Expenses and Other and Income Tax Expense changed between years as follows:

Other Operation and Maintenance expenses decreased $35 million primarily due to the following:

- An $84 million decrease due to distribution expense recorded in 2007 for ice storm costs incurred in January and December 2007 and a $74 million decrease related to the deferral of these costs in the first quarter of 2008. See “Oklahoma 2007 Ice Storms” section of Note 4.
- A $77 million decrease related to the recording of NSR settlement costs in September 2007. We are pursuing recovery of these expenses in certain of our affected jurisdictions.
- A $9 million decrease related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia’s share of previously expensed NSR settlement costs.

These decreases were partially offset by:

- A $60 million increase in recoverable PJM expenses in Ohio.
- A $38 million increase in tree trimming, reliability and other transmission and distribution expenses.
- A $28 million increase in generation plant operations and maintenance expense.
- A $28 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
- A $22 million increase due to storm costs incurred in 2008 by SWEPCo and I&M.
- A $13 million increase in maintenance expense at the Cook Plant.
- A $12 million increase due to the amortization of deferred 2007 Oklahoma ice storm costs in 2008.
- A $10 million increase related to the write-off of the unrecoverable pre-construction costs for PSO’s cancelled Red Rock Generating Facility in the first quarter of 2008.

Gain on Disposition of Assets, Net decreased $19 million primarily due to the expiration of the earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2007, we received the final earnings sharing payment of $20 million.

Depreciation and Amortization expense decreased $33 million primarily due to lower commission-approved depreciation rates in Indiana, Michigan, Oklahoma and Texas and lower Ohio regulatory asset amortization, partially offset by higher depreciable property balances and prior year adjustments related to the Virginia base rate case.

Interest Income increased $21 million primarily due to the favorable effect of claims for refund filed with the IRS.

Carrying Costs Income increased $32 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.

Other Income, Net increased $14 million primarily due to an increase in the equity component of AFUDC as a result of generation projects under construction.

Interest Expense increased $129 million primarily due to additional debt issued and higher interest rates on variable rate debt and interest expense of $47 million on off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.

Income Tax Expense increased $29 million due to an increase in pretax income.
Reconciliation of Year Ended December 31, 2006 to Year Ended December 31, 2007
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

<table>
<thead>
<tr>
<th>Year Ended December 31, 2006</th>
<th>$ 1,028</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Changes in Gross Margin:</strong></td>
<td></td>
</tr>
<tr>
<td>Retail Margins</td>
<td>372</td>
</tr>
<tr>
<td>Off-system Sales</td>
<td>69</td>
</tr>
<tr>
<td>Transmission Revenues</td>
<td>25</td>
</tr>
<tr>
<td>Other</td>
<td>9</td>
</tr>
<tr>
<td><strong>Total Change in Gross Margin</strong></td>
<td>475</td>
</tr>
</tbody>
</table>

| **Changes in Operating Expenses and Other:** |       |
| Other Operation and Maintenance | (226)  |
| Gain on Dispositions of Assets, Net | (47)   |
| Depreciation and Amortization     | (48)   |
| Taxes Other Than Income Taxes     | (13)   |
| Interest Income                  | (14)   |
| Carrying Costs Income            | (63)   |
| Other Income, Net                | 2      |
| Interest Expense                 | (120)  |
| **Total Change in Operating Expenses and Other** | (529)  |

| Income Tax Expense              | 57      |
| **Year Ended December 31, 2007** | $ 1,031 |

Income from Utility Operations Before Discontinued Operation and Extraordinary Loss of $1,031 million in 2007 was essentially flat when compared to 2006. An increase of $475 million in Gross Margin and a decrease of $57 million in Income Tax Expense were offset by an increase of $529 million in Operating Expenses and Other.

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

- Retail Margins increased $372 million primarily due to the following:
  - A $98 million increase in rates implemented in our Ohio jurisdictions, a $63 million rate increase implemented in our other east jurisdictions of Virginia, West Virginia and Kentucky, a $37 million increase in rates in Texas and a $16 million rate increase in Oklahoma.
  - A $105 million increase in usage related to weather. Compared to the prior year, our eastern region and western region experienced 22% and 33% increases, respectively, in heating degree days. Also, our eastern region experienced a 37% increase in cooling degree days which was partially offset by an 8% decrease in cooling degree days in our western region.
  - A $100 million increase related to increased residential and commercial usage and customer growth.
  - A $96 million increase due to the return of Ormet, an industrial customer in Ohio, effective January 1, 2007. See “Ormet” section of Note 4.
  - A $49 million increase in sales to municipal, cooperative and other wholesale customers primarily resulting from new power supply contracts.

These increases were partially offset by:

- A $67 million decrease in PJM financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market.
- A $53 million decrease due to PJM’s revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007.
- A $24 million decrease due to increased PJM ancillary costs.
- A $17 million decrease due to a 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.
• Margins from Off-system Sales increased $69 million primarily due to higher trading margins and favorable fuel recovery adjustments in our western territory, offset by lower east physical off-system sales margins mostly due to lower volumes and PJM’s implementation of marginal-loss pricing effective June 1, 2007.
• Transmission Revenues increased $25 million primarily due to higher revenue in ERCOT and our eastern region.
• Other Revenues increased $9 million primarily due to higher securitization revenue at TCC resulting from the $1.7 billion securitization in October 2006 offset by fewer gains on sales of emissions allowances. Securitization revenue represents amounts collected to recover securitization bond principal and interest payments related to TCC’s securitized transition assets and are fully offset by amortization and interest expenses.

Utility Operating Expenses and Other and Income Tax Expense changed between years as follows:
• Other Operation and Maintenance expenses increased $226 million primarily due to a $77 million expense resulting from the NSR settlement and an $81 million increase in storm restoration primarily in Oklahoma. The remaining increase relates to generation expenses from plant outages and base operations.
• Gain on Disposition of Assets, Net decreased $47 million primarily related to an earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2006, we received $70 million from Centrica for earnings sharing and in 2007 we received $20 million as the earnings sharing agreement expired.
• Depreciation and Amortization expense increased $48 million primarily due to increased Ohio regulatory asset amortization related to recovery of IGCC pre-construction costs, increased Texas securitized transition asset amortization and higher depreciable property balances, partially offset by commission-approved lower depreciation rates in Indiana, Michigan and Virginia.
• Carrying Costs Income decreased $63 million primarily due to TCC’s commencement of stranded cost recovery in October 2006, thus eliminating the accrual of carrying costs income, partially offset by higher carrying costs income related to APCo’s Virginia E&R cost deferrals.
• Interest Expense increased $120 million primarily due to additional debt issued in 2006 and 2007 including TCC securitization bonds as well as higher rates on variable rate debt.
• Income Tax Expense decreased $57 million due to unfavorable federal income tax adjustments in 2006 and favorable state tax return adjustments in 2007.

**AEP River Operations**

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $61 million in 2007 to $55 million in 2008 primarily due to rising diesel fuel prices, travel restrictions caused by significant flooding on various internal waterways throughout 2008, the impact of Hurricanes Ike and Gustav and other adverse operating conditions. Additionally, decreases in import demand and grain export demand have resulted in lower freight demand, largely the result of a slowing U.S. economy.

2007 Compared to 2006

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $80 million in 2006 to $61 million in 2007. AEP River Operations operated approximately 10% more barges in 2007 than 2006; however, revenue remained flat as reduced imports, primarily steel and cement continued to depress freight rates and reduce northbound loadings. Operating expenses were up for 2007 compared to 2006 primarily due to the cost of the increased fleet size, rising fuel costs and wage increases.
**Generation and Marketing**

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $67 million in 2007 to $65 million in 2008 primarily due to the sale in 2007 of our equity investment in Sweeny and related contracts which resulted in $37 million of after-tax income offset by higher gross margins from marketing activities and improved plant performance and hedging activities from our share of the Oklauion Power Station.

2007 Compared to 2006

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased from $12 million in 2006 to $67 million in 2007. The increase primarily relates to the sale in 2007 of our equity investment in Sweeny and related contracts which resulted in income. Revenues increased primarily due to certain existing ERCOT energy contracts, which were transferred from our Utility Operations segment on January 1, 2007, and favorable marketing contracts with municipalities and cooperatives in ERCOT. The increase in revenues was partially offset by increased purchased power and operating expenses.

**All Other**

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased to $133 million in 2008 from a $15 million loss in 2007. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM. The settlement was recorded as a pretax credit to Asset Impairments and Other Related Charges of $255 million in the accompanying Consolidated Statements of Income.

2007 Compared to 2006

Loss Before Discontinued Operations and Extraordinary Loss from All Other decreased from $128 million in 2006 to $15 million in 2007. The decrease in the loss primarily relates to a $136 million after-tax impairment of the Plaquemine Cogeneration Facility in 2006 offset by an increase in interest expense of $45 million related to the Bank of America and HPL cushion gas dispute and lower income from the sale of investment securities in 2007.

**AEP System Income Taxes**

2008 Compared to 2007

Income Tax Expense increased $126 million between 2007 and 2008 primarily due to an increase in pretax book income.

2007 Compared to 2006

Income Tax Expense increased $31 million between 2006 and 2007 primarily due to an increase in pretax book income, partially offset by recording federal and state income tax adjustments related to recent audit settlements reached with the IRS and other taxing jurisdictions.
FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2008, we maintained our strong financial condition as reflected by our issuance of $2.8 billion of long-term debt primarily to fund our construction program, refinance auction-rate debt and retire debt maturities.

Debt and Equity Capitalization

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008 ($ in millions)</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Debt, including amounts due within one year</td>
<td>$15,983 55.7%</td>
<td>$14,994 58.1%</td>
</tr>
<tr>
<td>Short-term Debt</td>
<td>1,976 6.9</td>
<td>660 2.6</td>
</tr>
<tr>
<td>Total Debt</td>
<td>17,959 62.6</td>
<td>15,654 60.7</td>
</tr>
<tr>
<td>Common Equity</td>
<td>10,693 37.2</td>
<td>10,079 39.1</td>
</tr>
<tr>
<td>Preferred Stock</td>
<td>61 0.2</td>
<td>61 0.2</td>
</tr>
<tr>
<td><strong>Total Debt and Equity Capitalization</strong></td>
<td><strong>$28,713 100.0%</strong></td>
<td><strong>$25,794 100.0%</strong></td>
</tr>
</tbody>
</table>

Our ratio of debt to total capital increased from 60.7% to 62.6% in 2008 due to our issuance of debt to fund construction and our strategy to deal with the credit situation by drawing $2 billion from our credit facilities.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include long-term debt, sale-leaseback or leasing agreements and common stock.

Capital Markets

In 2008, the domestic and world economies experienced significant slowdowns. Concurrently, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting our access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications since we rely on continuing access to capital to fund operations and capital expenditures.

We believe we have adequate liquidity through 2009 under our existing credit facilities. However, the current credit markets are constraining our ability to issue new debt, including commercial paper, and refinance existing debt. Approximately $300 million (excluding payments due for securitization bonds which we recover from ratepayers) of our $16 billion of long-term debt as of December 31, 2008 will mature in 2009. We intend to refinance these maturities. To support our operations, we have $3.9 billion in aggregate credit facility commitments. These commitments include 27 different banks with no one bank having more than 10% of our total bank commitments. In 2008, we borrowed $2 billion under our credit agreements during this period of market disruptions and renewed our sale of receivables agreement with a $700 million commitment.

During the fourth quarter of 2008, we issued new debt including $129 million of pollution control bonds at 7.125% and an $85 million 3-year variable term loan at 3.2% as of December 31, 2008. In 2009, I&M issued $475 million of 7% senior notes due 2019 and PSO issued $34 million of 5.25% Pollution Control Bonds due 2014. However, our ability to issue debt continues to be constrained as a result of current market conditions.

We cannot predict the length of time the current credit situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates. When market conditions improve, we plan to repay a portion of the amounts drawn under the credit facilities and issue commercial paper and long-term debt. If there is not an improvement in access to capital, we believe that we have adequate liquidity to support our planned business operations and construction program through 2009.
In the first quarter of 2008, bond insurers’ exposure in connection with developments in the subprime credit market resulted in increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates. Consequently, we chose to exit the auction-rate debt market and reduced our outstanding auction-rate securities from the December 2007 balance by $1.2 billion. As of December 31, 2008, $272 million of our auction-rate tax-exempt long-term debt (rates range between 2.034% and 13%) remained outstanding with rates reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures.

As of December 31, 2008, approximately $218 million of the $272 million of outstanding auction-rate debt relates to a lease structure with JMG that we are unable to refinance without JMG’s consent. The rates for this debt range from 6.388% to 13%. The initial term for the JMG lease structure matures on March 31, 2010. We are evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO.

**Credit Facilities**

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2008, our available liquidity was approximately $1.9 billion as illustrated in the table below:

<table>
<thead>
<tr>
<th>Amount (in millions)</th>
<th>Maturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commercial Paper Backup:</td>
<td></td>
</tr>
<tr>
<td>Revolving Credit Facility $1,500</td>
<td>March 2011</td>
</tr>
<tr>
<td>Revolving Credit Facility 1,454 (a)</td>
<td>April 2012</td>
</tr>
<tr>
<td>Revolving Credit Facility 627 (a)</td>
<td>April 2011</td>
</tr>
<tr>
<td>Revolving Credit Facility 338 (a)</td>
<td>April 2009</td>
</tr>
<tr>
<td>Total 3,919</td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents 411</td>
<td></td>
</tr>
<tr>
<td><strong>Total Liquidity Sources</strong> 4,330</td>
<td></td>
</tr>
<tr>
<td>Less: Cash Drawn on Credit Facilities 1,969</td>
<td></td>
</tr>
<tr>
<td>Letters of Credit Issued 434</td>
<td></td>
</tr>
<tr>
<td><strong>Net Available Liquidity</strong> $1,927</td>
<td></td>
</tr>
</tbody>
</table>

(a) Reduced by Lehman Brothers Holdings Inc.’s commitment amount of $81 million following its bankruptcy.

The revolving credit facilities for commercial paper backup were structured as two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $46 million following its bankruptcy. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. In 2008, we borrowed $2 billion under these credit facilities at a LIBOR rate. The maximum amount of commercial paper outstanding during 2008 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2008 was 3.32%. No commercial paper was outstanding at December 31, 2008 due to market conditions.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, we may issue letters of credit. As of December 31, 2008, $372 million of letters of credit were issued under the 3-year credit agreement to support variable rate Pollution Control Bonds.
**Sale of Receivables**

In 2008, we renewed our sale of receivables agreement through October 2009. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables. We intend to extend or replace the sale of receivables agreement at maturity.

**Master Lease Agreements**

During 2008, GE Capital Commercial Inc. (GE) notified us that they terminated our Master Leasing Agreements. In 2010 and 2011, we will be required to purchase all equipment under the terminated leases and pay GE an amount equal to the unamortized value of all equipment then leased. We expect to enter into replacement leasing arrangements for new equipment by the end of 2009 and for the equipment affected by the termination prior to their repayment due dates in 2010 and 2011.

In December 2008, we signed two new master lease agreements with The Huntington National Bank and RBS Asset Finance, Inc. for one-year commitment periods. The new agreements allow lease terms up to 10 years with variable and fixed rate options. The initial rates for issuances under the new leases were approximately 4% fixed and 3% variable. Management believes that these leasing agreements are adequate for our 2009 leased property acquisitions.

**Investments in Auction-Rate Securities**

Prior to June 30, 2008, we sold all of our investment in auction-rate securities at par.

**Debt Covenants and Borrowing Limitations**

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined in our revolving credit agreements. At December 31, 2008, this contractually-defined percentage was 58.1%. Nonperformance of these covenants could result in an event of default under these credit agreements. In addition, the acceleration of certain of our subsidiaries’ or our payment obligations prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable. At December 31, 2008, we complied with all of the covenants contained in these credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2008, we had not exceeded those authorized limits.

**Dividend Policy and Restrictions**

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 395 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in January 2009. Future dividends may vary depending upon our profit levels, operating cash flows and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on $315 million of our Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our cash flows, financial condition or limit any dividend payments in the foreseeable future.
Credit Ratings

Our current credit ratings are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Moody’s</th>
<th>S&amp;P</th>
<th>Fitch</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP Short Term Debt</td>
<td>P-2</td>
<td>A-2</td>
<td>F-2</td>
</tr>
<tr>
<td>AEP Senior Unsecured Debt</td>
<td>Baa2</td>
<td>BBB</td>
<td>BBB</td>
</tr>
</tbody>
</table>

In 2009, Moody’s:

- Placed AEP on negative outlook due to concern about overall credit worthiness, pending rate cases and recessionary pressures.
- Placed OPCo, SWEPCo, TCC and TNC on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries.
- Affirmed the stable rating outlooks for CSPCo, I&M, KPCo and PSO.
- Changed the rating outlook for APCo from negative to stable due to recent rate recoveries in Virginia and West Virginia.

If we receive a downgrade in our credit ratings by one of the rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Managing our cash flows is a major factor in maintaining our liquidity strength.

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
<td>$ 178</td>
<td>$ 301</td>
<td>$ 401</td>
</tr>
<tr>
<td>Net Cash Flows from Operating Activities</td>
<td>2,576</td>
<td>2,388</td>
<td>2,732</td>
</tr>
<tr>
<td>Net Cash Flows Used for Investing Activities</td>
<td>(4,027)</td>
<td>(3,921)</td>
<td>(3,743)</td>
</tr>
<tr>
<td>Net Cash Flows from Financing Activities</td>
<td>1,684</td>
<td>1,410</td>
<td>911</td>
</tr>
<tr>
<td><strong>Net Increase (Decrease) in Cash and Cash Equivalents</strong></td>
<td>233</td>
<td>(123)</td>
<td>(100)</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
<td>$ 411</td>
<td>$ 178</td>
<td>$ 301</td>
</tr>
</tbody>
</table>

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs.

Operating Activities

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>$ 1,380</td>
<td>$ 1,089</td>
<td>$ 1,002</td>
</tr>
<tr>
<td>Less: Discontinued Operations, Net of Tax</td>
<td>(12)</td>
<td>(24)</td>
<td>(10)</td>
</tr>
<tr>
<td><strong>Income Before Discontinued Operations</strong></td>
<td>1,368</td>
<td>1,065</td>
<td>992</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>1,483</td>
<td>1,513</td>
<td>1,467</td>
</tr>
<tr>
<td>Other</td>
<td>(275)</td>
<td>(190)</td>
<td>273</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Operating Activities</strong></td>
<td>$ 2,576</td>
<td>$ 2,388</td>
<td>$ 2,732</td>
</tr>
</tbody>
</table>

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.4 billion and $1.5 billion of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, material and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.
Net Cash Flows from Operating Activities were $2.4 billion in 2007 consisting primarily of Income Before Discontinued Operations of $1.1 billion and $1.5 billion of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items resulted in lower cash from operations due to increased accounts receivable of $113 million for new contracts in the generation and marketing segment and increased utility segment receivables and the CTC refunds in Texas.

Net Cash Flows from Operating Activities were approximately $2.7 billion in 2006 consisting primarily of Income Before Discontinued Operations of $992 million and $1.5 billion of noncash Depreciation and Amortization. Under-recovered fuel costs decreased due to recoveries under proceedings we initiated in Oklahoma, Texas, Virginia and Arkansas during 2005. The Other category represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities.

**Investing Activities**

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Expenditures</td>
<td>$ (3,800)</td>
<td>$ (3,556)</td>
<td>$ (3,528)</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(160)</td>
<td>(512)</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>90</td>
<td>222</td>
<td>186</td>
</tr>
<tr>
<td>Other</td>
<td>(157)</td>
<td>(75)</td>
<td>(401)</td>
</tr>
<tr>
<td><strong>Net Cash Flows Used for Investing Activities</strong></td>
<td>$ (4,027)</td>
<td>$ (3,921)</td>
<td>$ (3,743)</td>
</tr>
</tbody>
</table>

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investment.

Net Cash Flows Used for Investing Activities were $3.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan and purchases of gas-fired generating units.

Net Cash Flows Used for Investing Activities were $3.7 billion in 2006 primarily due to Construction Expenditures for our environmental investment plan.

We forecast approximately $2.6 billion of construction expenditures for 2009. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through net income and financing activities.

**Financing Activities**

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Issuance of Common Stock</td>
<td>$ 159</td>
<td>$ 144</td>
<td>$ 99</td>
</tr>
<tr>
<td>Issuance/Retirement of Debt, Net</td>
<td>2,266</td>
<td>1,902</td>
<td>1,420</td>
</tr>
<tr>
<td>Dividends Paid on Common Stock</td>
<td>(660)</td>
<td>(630)</td>
<td>(591)</td>
</tr>
<tr>
<td>Other</td>
<td>(81)</td>
<td>(6)</td>
<td>(17)</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Financing Activities</strong></td>
<td>$ 1,684</td>
<td>$ 1,410</td>
<td>$ 911</td>
</tr>
</tbody>
</table>

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity in the current credit market. We paid common stock dividends of $660 million.

Net Cash Flows from Financing Activities were $1.4 billion in 2007 primarily from issuance of debt to fund our construction program. We paid common stock dividends of $630 million.

Net Cash Flows from Financing Activities were $911 million in 2006 primarily from issuance of the Texas Securitization Bonds. We paid common stock dividends of $591 million and issued and retired debt securities.
The following financing activities occurred during 2008:

*Common Stock:*
- During 2008, we issued 4,394,552 shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $159 million.
- During 2008, we contributed 1,250,000 shares of common stock held in the treasury to the AEP Foundation.

*Debt:*
- During 2008, we issued approximately $2.8 billion of long-term debt, including $1.6 billion of senior notes at a weighted average interest rate of 6.43%, $809 million of pollution control revenue bonds ($367 million at variable rates and $442 million at a weighted average fixed interest rate of 5.67%), a variable rate $85 million 3-year term loan (3.2% at December 31, 2008) and $315 million of junior subordinated debentures at 8.75%. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions and construction programs. We also remarketed $182 million of pollution control revenue bonds with new weighted average interest rates of 4.97% under the terms of their original issuance documents.
- During 2008, we entered into $150 million of interest rate derivatives and settled $420 million of such transactions. The settlements resulted in a net cash expenditure of $11 million. As of December 31, 2008, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of $100 million in order to hedge risk exposure of variable interest rate debt.
- At December 31, 2008, we had credit facilities totaling $3 billion to support our commercial paper program and short-term borrowing. As of December 31, 2008, we had $2 billion borrowed under the credit facilities and no commercial paper outstanding due to the current credit market. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $1.2 billion in May 2008 and the weighted average interest rate of commercial paper outstanding during the year was 3.32%.

In 2009:
- We issued the following debt:
  - In February 2009, PSO issued $34 million of 5.25% Pollution Control Bonds due 2014.
- We retired the following debt:
  - In January 2009, TCC retired $81 million of its outstanding Securitization Bonds.
- Our capital investment plans for 2009 will require additional funding from the capital markets.

**Off-balance Sheet Arrangements**

Under a limited set of circumstances, we enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

**AEP Credit**

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in a portion of the receivables it acquires from affiliated utilities to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and, in accordance with GAAP, are not required to consolidate these entities. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies’ receivables and accelerate cash collections.
AEP Credit’s sale of receivables agreement expires in October 2009. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $700 million to purchase receivables from AEP Credit. At December 31, 2008, $650 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. For the remaining receivables left unsold to the commercial paper conduits and banks, AEP Credit maintains an interest in the receivables and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

**Rockport Plant Unit 2**

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $1 billion as of December 31, 2008.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

**Railcars**

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three, consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years, via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $43 million for the remaining railcars as of December 31, 2008. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five year renewal. At December 31, 2008, the maximum potential loss was approximately $25 million ($17 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.
Summary Obligation Information

Our contractual cash obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2008:

### Payments Due by Period

<table>
<thead>
<tr>
<th>Contractual Cash Obligations</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short-term Debt (a)</td>
<td>$ 1,976</td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 1,976</td>
</tr>
<tr>
<td>Interest on Fixed Rate Portion of Long-term Debt (b)</td>
<td>895</td>
<td>1,604</td>
<td>1,480</td>
<td>9,731</td>
<td>13,710</td>
</tr>
<tr>
<td>Fixed Rate Portion of Long-term Debt (c)</td>
<td>362</td>
<td>2,260</td>
<td>1,898</td>
<td>10,403</td>
<td>14,923</td>
</tr>
<tr>
<td>Variable Rate Portion of Long-term Debt (d)</td>
<td>85</td>
<td>400</td>
<td>-</td>
<td>639</td>
<td>1,124</td>
</tr>
<tr>
<td>Capital Lease Obligations (e)</td>
<td>94</td>
<td>119</td>
<td>46</td>
<td>149</td>
<td>408</td>
</tr>
<tr>
<td>Noncancelable Operating Leases (e)</td>
<td>336</td>
<td>771</td>
<td>437</td>
<td>1,671</td>
<td>3,215</td>
</tr>
<tr>
<td>Fuel Purchase Contracts (f)</td>
<td>3,788</td>
<td>4,832</td>
<td>2,590</td>
<td>7,362</td>
<td>18,572</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (g)</td>
<td>51</td>
<td>73</td>
<td>40</td>
<td>268</td>
<td>432</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (h)</td>
<td>661</td>
<td>993</td>
<td>613</td>
<td>-</td>
<td>2,267</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 8,248</strong></td>
<td><strong>$ 11,052</strong></td>
<td><strong>$ 7,104</strong></td>
<td><strong>$ 30,223</strong></td>
<td><strong>$ 56,627</strong></td>
</tr>
</tbody>
</table>

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 14. Represents principal only excluding interest.
(d) See Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.75% and 13.0% at December 31, 2008.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

Our FIN 48 liabilities of $87 million are not included above because we cannot reasonably estimate the cash flows by period.

Our minimum pension funding requirements are not included in the above table. As of December 31, 2008, the decline in pension asset values will not require us to make a contribution in 2009. We currently estimate that we will need to make minimum contributions to our pension plan of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.
In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2008, our commitments outstanding under these agreements are summarized in the table below:

<table>
<thead>
<tr>
<th>Other Commercial Commitments</th>
<th>Amount Expired Per Period (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Less Than 1 year</td>
</tr>
<tr>
<td>Standby Letters of Credit (a)</td>
<td>$ 433</td>
</tr>
<tr>
<td>Guarantees of the Performance of Outside Parties (b)</td>
<td>-</td>
</tr>
<tr>
<td>Guarantees of Our Performance (c)</td>
<td>790</td>
</tr>
<tr>
<td>Total Commercial Commitments</td>
<td>$ 1,223</td>
</tr>
</tbody>
</table>

(a) We enter into standby letters of credit. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. As the Parent, we issued all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. The maximum future payments of these letters of credit are $434 million with maturities ranging from March 2009 to March 2010. As the Parent of all of these subsidiaries, AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties if these letters of credit are drawn. See “Letters of Credit” section of Note 6.

(b) See “Guarantees of Third-Party Obligations” section of Note 6.

(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

JOINT VENTURE INITIATIVES

AEP is currently participating in the following transmission initiatives:

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Location</th>
<th>Projected Completion Date</th>
<th>Owners (Ownership %)</th>
<th>Total Estimated Project Costs at Completion (in thousands)</th>
<th>AEP's Equity Method Investment at December 31, 2008 (in thousands)</th>
<th>Approved Return on Equity</th>
</tr>
</thead>
<tbody>
<tr>
<td>ETT</td>
<td>Texas (ERCOT)</td>
<td>2017</td>
<td>MEHC (50%) AEP (50%)</td>
<td>$1,300,000 (a)</td>
<td>$15,445</td>
<td>9.96%</td>
</tr>
<tr>
<td>PATH (b)</td>
<td>Ohio/West Virginia</td>
<td>2013</td>
<td>Allegheny Energy (50%) AEP (50%)</td>
<td>1,800,000 (c)</td>
<td>6,463</td>
<td>14.3%</td>
</tr>
<tr>
<td>Tallgrass</td>
<td>Oklahoma</td>
<td>2013</td>
<td>OGE Energy (50%) ETA (50%) (d)</td>
<td>500,000</td>
<td>109</td>
<td>12.8%</td>
</tr>
<tr>
<td>Prairie Wind</td>
<td>Kansas</td>
<td>2013</td>
<td>Westar Energy (50%) ETA (50%) (d)</td>
<td>600,000</td>
<td>31</td>
<td>12.8%</td>
</tr>
<tr>
<td>Pioneer</td>
<td>Indiana</td>
<td>2015</td>
<td>Duke Energy (50%) AEP (50%)</td>
<td>1,000,000</td>
<td>- (e)</td>
<td></td>
</tr>
</tbody>
</table>

(a) In addition to ETT’s current total estimated project costs of $1.3 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis. See “ETT” section of Note 4.

(b) In September 2007, AEP and Allegheny Energy Inc. formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC and its subsidiaries (PATH). The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM.

(c) PATH consists of the “Ohio Series,” the “West Virginia Series (PATH-WV),” both owned equally by Allegheny Energy and AEP and the “Allegheny Series” which is 100% owned by Allegheny Energy. The total project is estimated to cost approximately $1.8 billion. AEP’s estimated share of the project cost is approximately $600 million.

(d) ETA is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) and AEP. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP owns 25% of Tallgrass and Prairie Wind through its ownership interest in ETA.

(e) Currently seeking rate approval from the FERC.
**Electric Transmission Texas, LLC (Utility Operations Segment)**

In December 2007, we received approval from the PUCT to establish Electric Transmission Texas, LLC (ETT), as a joint venture company to fund, own and operate electric transmission assets in ERCOT. We do not consolidate ETT for financial reporting purposes. Our equity investment in ETT is included in Deferred Charges and Other on our Consolidated Balance Sheets. We provide services to ETT through service agreements. ETT plans to invest in additional transmission projects in ERCOT over the next several years.

In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the Competitive Renewable Energy Zone (CREZ) initiative. The CREZ initiative is the development of 2,400 miles of new transmission lines to transport electricity from 18,000 megawatts of planned wind farm capacity in west Texas to rapidly growing cities in eastern Texas. In January 2009, the PUCT announced its decision to authorize ETT to construct CREZ related projects. ETT has estimated that the PUCT’s decision authorizes ETT to construct $750 million to $850 million of new transmission assets. This estimated amount is included in ETT’s current $1.3 billion of projected transmission project costs.

In October 2008, the Travis County District Court ruled that the PUCT exceeded its authority by approving ETT’s application as a stand alone transmission utility without a service area under the wrong section of the statute. Management believes the ruling is incorrect. See “ETT” section of Note 4. Management cannot predict the outcome of this proceeding.

**Electric Transmission America, LLC (Utilities Operations Segment)**

In September 2007, we and MEHC formed Electric Transmission America, LLC (ETA) to pursue transmission opportunities located in North America, outside of ERCOT. We hold a 50% equity ownership interest in ETA. We do not consolidate ETA for financial reporting purposes. Our equity investment in ETA is included in Deferred Charges and Other on our Consolidated Balance Sheets.

**Potomac-Appalachian Transmission Highline (Utility Operations Segment)**

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC and its subsidiaries (PATH). The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM. We will equally share the ownership and management of the West Virginia facilities (PATH-WV) and the Ohio facilities (PATH-OH) within PATH with AYE; other facilities within PATH are owned 100% by AYE. We do not consolidate PATH-WV for financial reporting purposes. Our equity investment in PATH-WV is included in Deferred Charges and Other on our Consolidated Balance Sheets. We and AYE provide services to the PATH companies through service agreements.

In December 2007, PATH-WV filed an application with the FERC for approval of a transmission formula rate to recover its cost of providing transmission service, including costs incurred prior to the formula rates going into effect. PATH-WV requested an incentive return on equity of 14.3% and the inclusion of CWIP in rate base. In February 2008, the FERC approved PATH-WV’s request except for the cost of service formula and formula rate implementation protocols and ordered that the formula rates be implemented March 1, 2008, subject to true-up. Motions for rehearing were filed by intervening parties in March 2008. Management cannot predict the outcome of these motions.
SIGNIFICANT FACTORS

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amended the restructuring law effective July 31, 2008 and required electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities could include a fuel cost recovery mechanism (FCR) in their ESP filing. Electric utilities also had an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, would have transitioned CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve and/or modify each utility’s ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than an MRO. Both alternatives involve a “significantly excessive earnings” (SEET) test based on what public companies, including other utilities with similar risk profiles, earn on equity.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo’s and OPCo’s ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a FCR that primarily includes fuel costs, purchased power costs, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The FCR is proposed to be phased into customer bills over the three-year period from 2009 through 2011 and recovered with a weighted average cost of capital carrying cost deferral over seven years from 2012 through 2018. If the ESPs are approved as filed, effective with the implementation of the ESPs, CSPCo and OPCo will defer fuel cost over/under-recoveries and related carrying costs, including amounts unrecovered through the phase in period, for future recovery.

In addition to the FCR, the requested ESP increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include recovery for programs for smart metering initiatives, economic development, mandated energy efficiency, renewable resources and peak demand reduction programs.

Within the ESP requests, CSPCo and OPCo would also recover existing regulatory assets of $47 million and $39 million, respectively, for customer choice implementation and line extension carrying costs incurred through December 2008. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $31 million and $23 million, respectively, through December 2008. The PUCO had previously issued orders allowing deferral of these costs. Such costs would be recovered over an 8-year period beginning January 2011. If the PUCO does not approve recovery of these regulatory assets in this or some future proceeding, it would have an adverse effect on future net income and cash flows.

Hearings were held in November and December 2008. Many intervenors filed opposing testimony. CSPCo and OPCo requested retroactive application of the new rates, including the FCR, back to the start of the January 2009 billing cycle upon approval of the ESPs. The RSP rates were effective for the years ended December 31, 2006, 2007 and 2008 under which CSPCo and OPCo had three annual generation rate increases of 3% and 7%, respectively. The RSP also allowed additional annual generation rate increases of up to an average of 4% per year to recover new governmentally-mandated costs. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. A motion to dismiss the application has been filed by Ohio Partners for Affordable Energy, while the Ohio Consumers’ Counsel has filed comments opposing the application. The PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO issues a ruling on the ESPs or the end of the March 2009 billing cycle, whichever comes first. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs. CSPCo and OPCo anticipate a final order from the PUCO during the first quarter of 2009.
Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. Our current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. In January 2009, I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the fuel cost forecast period of April through September 2009. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded its net other true-up regulatory liabilities of $375 million from October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 million, respectively. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC’s true-up recoveries.

In March 2007, the Texas District Court judge hearing the appeals of the true-up order affirmed the PUCT’s April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs and remanded this matter to the PUCT for further consideration. The District Court judge also determined that the PUCT improperly reduced TCC’s net stranded plant costs for commercial unreasonableness.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but two major respects. It reversed the District Court’s unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the “excess earnings” that had already been refunded to affiliated retail electric providers. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earning based upon the reasons discussed in the “TCC Excess Earnings” section within “Texas Rate Matters”. The favorable commercial unreasonableness judgment entered by the District Court was not reversed. The Texas Court of Appeals denied intervenors’ motion for rehearing. In May 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not determined if it will grant review.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. Appeals brought by intervenors and TNC of the final true-up order remain pending in state court.
Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future net income, cash flows and financial condition.

New Generation

In 2008, AEP completed or is in various stages of construction of the following generation facilities:

<table>
<thead>
<tr>
<th>Operating Company</th>
<th>Project Name</th>
<th>Location</th>
<th>Total Projected Cost (a) (in millions)</th>
<th>CWIP (b) (in millions)</th>
<th>Fuel Type</th>
<th>Plant Type</th>
<th>Nominal MW Capacity</th>
<th>Commercial Operation Date (Projected)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>Southwestern</td>
<td>Oklahoma</td>
<td>$56</td>
<td>$</td>
<td>Gas</td>
<td>Simple-cycle</td>
<td>150</td>
<td>2008</td>
</tr>
<tr>
<td>PSO</td>
<td>Riverside</td>
<td>Oklahoma</td>
<td>58</td>
<td>-</td>
<td>Gas</td>
<td>Simple-cycle</td>
<td>150</td>
<td>2008</td>
</tr>
<tr>
<td>AEGCo</td>
<td>Dresden</td>
<td>Ohio</td>
<td>310</td>
<td>179</td>
<td>Gas</td>
<td>Combined-cycle</td>
<td>580</td>
<td>2013</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Stall</td>
<td>Louisiana</td>
<td>384</td>
<td>252</td>
<td>Gas</td>
<td>Combined-cycle</td>
<td>500</td>
<td>2010</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Turk</td>
<td>Arkansas</td>
<td>1,628(f)</td>
<td>510</td>
<td>Coal</td>
<td>Ultra-supercritical</td>
<td>600(f)</td>
<td>2012</td>
</tr>
<tr>
<td>APCo</td>
<td>Mountaineer</td>
<td>West Virginia</td>
<td>(g)</td>
<td>(g)</td>
<td>Coal</td>
<td>IGCC</td>
<td>629</td>
<td>(g)</td>
</tr>
<tr>
<td>CSPCo/OPCo</td>
<td>Great Bend</td>
<td>Ohio</td>
<td>(g)</td>
<td>(g)</td>
<td>Coal</td>
<td>IGCC</td>
<td>629</td>
<td>(g)</td>
</tr>
</tbody>
</table>

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(e) In September 2007, AEGCo purchased the partially completed Dresden Plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the “Total Projected Cost” section above.
(f) SWEPCo plans to own approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See “Turk Plant” section below.
(g) Construction of IGCC plants are pending regulatory approvals. See “IGCC Plants” section below.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC, (b) capping CO₂ emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT’s order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT’s grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In November 2008, SWEPCo received the air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant’s permit is heard. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit.
In January 2008 and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor’s Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission’s final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission’s report, it could impact SWEPCo’s proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of December 31, 2008, SWEPCo has capitalized approximately $510 million of expenditures (including AFUDC) and has significant contractual construction commitments for an additional $727 million. As of December 31, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

**IGCC Plants**

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying APCo’s request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through December 31, 2008, APCo deferred for future recovery preconstruction IGCC costs of $20 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers’ Counsel filed a motion with the PUCO requesting all Phase 1 cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers’ Counsel’s motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

**Pension and Postretirement Benefit Plans**

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plans (collectively the Pension Plans). We merged the Qualified Plans at December 31, 2008. Additionally, we entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the nonqualified, supplemental plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.
The following table shows the net periodic cost and assumed rate of return on the Plans’ assets:

<table>
<thead>
<tr>
<th></th>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Net Periodic Benefit Cost</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pension Plans</td>
<td>$ 51</td>
<td>$ 50</td>
<td>$ 71</td>
<td></td>
</tr>
<tr>
<td>Postretirement Plans</td>
<td>80</td>
<td>81</td>
<td>96</td>
<td></td>
</tr>
<tr>
<td><strong>Assumed Rate of Return</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pension Plans</td>
<td>8.00%</td>
<td>8.50%</td>
<td>8.50%</td>
<td></td>
</tr>
<tr>
<td>Postretirement Plans</td>
<td>8.00%</td>
<td>8.00%</td>
<td>8.00%</td>
<td></td>
</tr>
</tbody>
</table>

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates on return on the Plans’ assets. In developing the expected long-term rate of return assumption for 2009, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets as well as our ten-year average return, for the period ended December 2008, of approximately 3%. We anticipate that the investment managers we employ for the Plans will generate future returns averaging 8.00% for the Pension Plan and 7.75% for the Postretirement Plans.

The expected long-term rate of return on the Plans’ assets is based on our targeted asset allocation and our expected investment returns for each investment category. The investment returns for the Postretirement Plans are assumed to be slightly less than those of the Pension Plans as a portion of the returns for the Postretirement Plans is taxable. Our assumptions are summarized in the following table:

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Assumed/Expected Long-term Rate of Return</th>
<th>Other Postretirement Benefit Plans</th>
<th>Assumed/Expected Long-term Rate of Return</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008 Actual Asset Allocation</td>
<td>2009 Target Asset Allocation</td>
<td>Equity</td>
<td>47%</td>
<td>55%</td>
</tr>
<tr>
<td>Real Estate</td>
<td>6%</td>
<td>5%</td>
<td>7.5%</td>
<td>-%</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>42%</td>
<td>39%</td>
<td>6.0%</td>
<td>43%</td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>5%</td>
<td>1%</td>
<td>3.5%</td>
<td>4%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Global capital markets experienced extreme volatility in 2008. The value of investments in our pension and OPEB trusts declined substantially due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds’ ability to make their required payments.

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 8% for the Pension Plans and 7.75% for the Postretirement Plans are reasonable long-term rates of return on the Plans’ assets despite the recent market volatility. The Pension Plans’ assets had an actual (loss) gain of (24.1)% and 9.2% for the years ended December 31, 2008 and 2007, respectively. The Postretirement Plans’ assets had an actual (loss) gain of (24.7)% and 8.6% for the years ended December 31, 2008 and 2007, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related
value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2008, we had cumulative losses of approximately $1 billion that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, “Employers’ Accounting for Pensions.”

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody’s Aa bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2008 under this method was 6.00% for the Pension Plans and 6.10% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans’ assets of 8.00%, a discount rate of 6.00% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $92 million, $145 million and $152 million in 2009, 2010 and 2011, respectively. Based on an expected rate of return on the OPEB plans’ assets of 7.75%, a discount rate of 6.10% and various other assumptions, we estimate Postretirement Plan costs will approximate $148 million, $140 million and $121 million in 2009, 2010 and 2011, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in “Pension and Other Postretirement Benefits” within the “Critical Accounting Estimates” section of this Management’s Financial Discussion and Analysis of Results of Operations.

The value of the Pension Plans’ assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007 primarily due to investment losses. The Qualified Plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of our Postretirement Plans’ assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007 primarily due to investment losses. The Postretirement Plans paid $120 million in benefits to plan participants during 2008.

Investments in trusts are stated at fair market value. We utilize our trustee’s external pricing service to measure the market value of the underlying investments. Our investment managers review and validate the prices utilized to determine fair market value. We also perform our own valuation testing to validate the market values of the actively traded securities. We receive audit reports of our trustee’s operating controls and valuation processes. Where possible, quoted prices on actively traded exchanges are used to determine value. Debt holdings that are not actively traded may be valued based on the observable pricing of comparable securities. Investments in commingled funds are generally not actively traded and are priced at a Net Asset Value (NAV) which is based on the underlying holdings of the funds. These holdings are typically actively traded equities or debt securities that may be valued in a manner similar to direct debt investments. Trust assets as of December 31, 2008 include approximately $244 million of real estate and private equity investments in the pension fund that are valued based on methods requiring judgment.

Our Qualified Plans were underfunded as of December 31, 2008. No contribution to the Qualified Plans is required under ERISA in 2009. Minimum contributions to the Qualified Plans of $365 million in 2010 and $258 million in 2011 are currently projected under ERISA and may vary significantly based on future market returns, changes in actuarial assumptions and other factors. Our nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation exceeded plan assets by $80 million and $77 million at December 31, 2008 and 2007, respectively.

Certain pension plans we sponsor contain a cash balance benefit feature. In 2008, the IRS issued Determination Letters confirming the tax exempt status of these plans including the cash balance benefit feature.

The Worker, Retiree and Employer Recovery Act of 2008 did not materially impact our plans.

**Nuclear Trust Funds**

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines.
We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives. We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at market value. We utilize our trustee’s external pricing service to measure the market value of the underlying investments held in these trusts. Our investment managers review and validate the prices utilized to determine fair market value. We also perform our own valuation testing to validate the market values of the actively traded securities. We receive audit reports of our trustee’s operating controls and valuation processes.

**Litigation**

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what their eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our net income.

**Environmental Litigation**

New Source Review (NSR) Litigation: The Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. In 2007, we settled this litigation by a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, we agreed to annual SO2 and NOx emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. We agreed to install FGD equipment at Big Sandy and at Muskingum River Plants no later than the end of 2015 and SCR and FGD emissions control equipment at Rockport Plant no later than the end of 2017 and 2019 for Unit 1 and Unit 2, respectively. We also agreed to install selective non-catalytic reduction, a NOx-reduction technology, at Clinch River Plant in 2009.

CSPCo jointly-owns Beckjord and Stuart Stations with Duke Energy Ohio, Inc. and Dayton Power and Light Company. A jury trial returned a verdict of no liability at the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. In October 2008, the court approved a settlement in a citizen suit action filed by Sierra Club against the jointly-owned units at Stuart Station. Under the settlement, the joint-owners of Stuart Station agreed to certain emission targets related to NOx, SO2 and PM. The joint-owners also agreed to make energy efficiency and renewable energy commitments that are conditioned on PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program.

**Environmental Matters**

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. The sources of these requirements include:

- Requirements under the CAA to reduce emissions of SO2, NOx and PM from fossil fuel-fired power plants; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants.

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO2 and other greenhouse gases (GHG) emissions to address concerns about global climate change. All of these matters are discussed below.
Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation’s air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

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

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and PM2.5. These new standards could increase the levels of SO2 and NOx reductions required from our facilities. The Federal EPA also established a lower standard for lead, and conducts periodic reviews for additional criteria pollutants including SO2 and NOx.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR). It requires specific reductions in SO2 and NOx emissions from power plants and assists states developing new SIPs to meet the NAAQS. CAIR reduces regional emissions of SO2 and NOx (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO2 by 50% by 2010, and by 65% by 2015. NOx emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reductions of both SO2 and NOx would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate CAIR and remanded the rule to the Federal EPA. In September 2008, the Federal EPA and other parties petitioned for rehearing. In December 2008, the D.C. Circuit Court of Appeals granted the Federal EPA’s petition and remanded the rule to the Federal EPA without vacatur, allowing CAIR to remain in effect while a new rulemaking is conducted. We are unable to predict how the Federal EPA will respond to the remand. States were required to develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which our power plants are located will be covered by CAIR and have or are developing CAIR SIPs. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals. The Federal EPA or states may elect to seek further reductions of SO2 and NOx in response to more stringent PM and ozone NAAQS.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO2 and NOx emissions in order to comply with CAIR. States were required to develop and submit their SIPs to implement CAMR by November 2006.

Various states and special interest groups challenged the rule in the D.C. Circuit Court of Appeals. The court ruled that the Federal EPA’s action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA, and vacated and remanded the federal rules for both new and existing coal-fired power plants to the Federal EPA. The Federal EPA filed a petition for review by the U.S. Supreme Court, but the new Federal EPA Administrator asked that the petition be withdrawn. We are unable to predict the outcome of this appeal or how the Federal EPA will respond to the remand.
The Acid Rain Program: The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO2 emissions of 8.9 million tons per year. The 1990 Amendments also contain requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. CAIR currently uses the SO2 allowances originally allocated through the Acid Rain Program as the basis for its SO2 cap-and-trade system. We are unable to predict if or how any replacement for CAIR will utilize the SO2 allowances from the Acid Rain Program.

Regional Haze: The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (Regional Haze program). In 2005, the Federal EPA issued its Clean Air Visibility Rule (CAVR), detailing how the CAA’s best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that CAIR will result in more visibility improvements than BART for power plants subject to it. Thus, states are allowed to substitute CAIR requirements in their Regional Haze program SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states (Oklahoma, Texas and Arkansas of the AEP System) not subject to CAIR requirements for SO2 and NOx, some additional controls will be required. The courts upheld the final rule.

In January 2009, the Federal EPA issued a determination that 37 states (including Indiana, Ohio, Oklahoma, Texas and Virginia) failed to submit SIP’s fulfilling the Regional Haze program requirements by the deadline, and commencing a 2-year period for the development of a Federal Implementation Plan (FIP) in these states. We are unable to predict if or how the remand of CAIR or the development of a FIP for certain states may affect our compliance obligations for the Regional Haze programs.

Estimated Air Quality Environmental Investments

The CAIR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. Our estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and our selected compliance alternatives and their costs. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

By the end of 2008, we installed SCR technology on over 11,380 MW of our eastern power plants to comply with NOx emission requirements. We comply with SO2 emission requirements by installing scrubbers and using alternate fuels and SO2 allowances. We receive allowances through allocation and purchase at either the annual Federal EPA auction or in the market. Decreasing allowance allocations, our diminishing SO2 allowance bank, increasing allowance costs, CAIR and commitments in the consent decree will require installation of additional controls on our power plants through 2019. We plan to install additional scrubbers on 9,000 MW for SO2 control. From 2009 to 2013, we estimate total environmental investment of $3.6 billion including investment in scrubbers and other SO2 equipment of approximately $2.6 billion. These estimates may be revised as a result of the court’s decision remanding the CAIR and CAMR. We will also incur additional operation and maintenance expenses in future years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Due to CAIR and the NSR settlement discussed above, we expect to incur additional costs for pollution control technology retrofits between 2014 and 2020 of approximately $3.3 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states’ implementation of these regulatory programs, including the potential for SIPs or FIPs that impose standards more stringent than CAIR; (2) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR; (3) the actual performance of the pollution control technologies installed on our units; (4) changes in costs for new pollution controls; (5) new generating technology developments; and (6) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.
We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future net income, cash flows and possibly financial condition.

**Clean Water Act Regulations**

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant’s cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. We expected additional capital and operating expenses, which the Federal EPA estimated could be $193 million for our plants. We undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates.

In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. We cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. We sought further review and filed for relief from the schedules included in our permits.

In April 2008, the U.S. Supreme Court agreed to review decisions from the Second Circuit Court of Appeals that limit the Federal EPA’s ability to weigh the retrofitting costs against environmental benefits. Management is unable to predict the outcome of this appeal.

**Potential Regulation of CO2 and Other GHG Emissions**

The scientific community, led largely by the Intergovernmental Panel on Climate Change, has provided scientific evidence that human activity, and particularly the combustion of fossil fuels, has increased the levels of GHG in the atmosphere and contributed to observed changes in the global climate system. These findings have led to proposals for substantial transformation of the world’s energy production and transportation systems in order to slow, and ultimately reduce, the production of CO2 and other GHG emissions sufficiently to reduce atmospheric concentrations. Because approximately 90% of the electricity generated by the AEP System is produced by the combustion of fossil fuels, we are helping to lead the discussion nationally and internationally to find a reasonable, achievable approach and enact federal energy policy that is realistic in time frame and does not seriously harm the U.S. economy. We also are developing advanced coal technologies so that coal can continue to be the important energy resource it is today. We support the adoption of an economy-wide, cap-and-trade GHG reduction program that allows us to provide reliable, reasonably priced electricity to our customers and that fosters the international participation that is necessary to make meaningful global progress on this global challenge.

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in GHG emissions. The U.S. signed the Kyoto Protocol in 1998, but the treaty was not submitted to the Senate for its consent. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. The first commitment period under the Kyoto Protocol ends in 2012. Negotiations designed to lead to a global agreement on limiting GHG emissions after the Kyoto Protocol expires have commenced, and are focused on flexible mechanisms that can address the concerns expressed by the U.S. and others regarding the global impacts of increasing emissions in developing economies, including China, Brazil, and India, and mitigating the economic impacts of GHG reductions in developed countries given current economic conditions.

Since 2005, several members of Congress have introduced bills that would regulate GHG emissions, including emissions from power plants. Congress has passed no legislation, but recent bills have received more serious consideration and some form of national legislation impacting the electric utility industry is likely to pass within the next few years. Such legislation is likely to take the form of direct regulation of GHG emissions through cap-and-trade provisions. In addition and related to climate change legislation, a national renewable portfolio standard, energy efficiency requirements for electric utilities and other measures may pass Congress in the next few years.
Several states have adopted programs that directly regulate GHG emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). We are taking steps to comply with these requirements. Through our recent purchases of wind power and the existing wind assets that we have developed and our future plans, our integrated resource plan contains a 10% renewable energy target by 2020, which is nearly double the level of renewable energy requirements in effect in our states. Our plans are based on the reasonable expectation that additional federal or state requirements may be enacted that will affect our system.

We support a reasonable approach to GHG emission reductions, including a mandate to achieve economy-wide reductions that recognizes a reliable and affordable electric supply is vital to economic stability. We have taken measurable, voluntary actions to reduce and offset our own GHG emissions. We participate in a number of voluntary programs to monitor, mitigate and reduce GHG emissions, including the Federal EPA’s Climate Leaders program, the DOE’s GHG reporting program and the Chicago Climate Exchange. Through the end of 2007, we reduced our emissions by a cumulative 46 million metric tons from adjusted baseline levels in 1998-2001 as a result of these voluntary actions. Our total GHG emissions in 2007 were 155.8 million metric tons. We estimate that our 2008 emission will be approximately 155 million metric tons and our cumulative reductions will be in excess of 51 metric million tons.

We believe that climate change is a global issue and that the United States should assume 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. We, along with the International Brotherhood of Electrical Workers (IBEW), proposed that a consistent national policy for reasonable GHG controls should include the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy GHG reduction technologies
- Removal of regulatory or economic barriers to GHG emission reductions
- Recognition for early actions/investments in GHG reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

In July 2007, we, along with several other utilities and labor unions, including the IBEW, announced support for the Low Carbon Economy Act of 2007. This legislation requires GHG reductions beginning in 2012 through an economy-wide cap-and-trade program. It contemplates reducing GHG emissions to their 2006 levels by 2020, and to their 1990 levels by 2030. Allowances to emit GHG would be allocated, auctioned or a combination of each, including a safety valve allowance price of $12 per metric ton, subject to increasing adjustments. The legislation also includes incentives for other nations to adopt measures to limit GHG emissions. We endorse this legislation because it sets reasonable and achievable reduction targets and includes key elements of the AEP-IBEW principles. We also support the Edison Electric Institute (EEI) principles for federal climate change legislation, including the consensus approach developed by EEI for the allocation of emission allowances.

President Obama has stated that he favors climate legislation that would reduce GHG emissions by 80% by 2050 and require the auctioning of all allowances. We oppose a 100% auction of GHG emission allowances, as it would substantially increase the costs of compliance on our system and increase customer rates. We support reasonable emission reduction targets that allow sufficient time for technology development and recognize that commercial scale technologies to provide substantial GHG emission reductions at new or existing electric generating units are not currently available.

While comprehensive economy-wide regulation of GHG emissions might be achieved through new legislation, several states and interest groups petitioned the Federal EPA to establish GHG emission standards under the existing requirements of the CAA. In April 2007, the U.S. Supreme Court reversed and remanded the Federal EPA’s determination that it lacked the authority to regulate GHG emissions from motor vehicles for purposes of climate change under the CAA. In response to the Supreme Court’s decision, the Federal EPA issued an Advance Notice of Proposed Rulemaking in July 2008 seeking comment on its analysis of the available evidence to support a finding that GHG emissions endanger human health or the environment under various provisions of the CAA, and the suitability of different provisions of the mobile source, stationary source, and permitting programs under the CAA to
effectively regulate GHG emissions. We agree with the assessment of the previous EPA Administrator that the existing authorities under the CAA are not well-suited to achieving economy-wide cost-effective reductions of GHG emissions. Shortly after taking office, President Obama directed the Federal EPA to re-examine a decision denying the request by the State of California for a waiver that would allow states to establish higher fuel efficiency standards as a means of reducing GHG emissions from mobile sources. Thirteen states have taken action that would implement the California standards if the Federal EPA issues such a waiver. While this waiver, if issued, would have no immediate impact on stationary sources, should the Federal EPA choose to take other actions to regulate GHG emissions under the CAA, they could have a material impact upon the costs of operating our fossil-fueled generating plants.

In addition, certain groups have filed lawsuits alleging that emissions of CO₂ and other GHGs are a “public nuisance” and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in two pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See “Carbon Dioxide Public Nuisance Claims” and “Alaskan Villages’ Claims” sections of Note 6.

We expect that GHG emissions, including those associated with the operation of our fossil-fueled generating plants, will be limited by law or regulation in the future. The manner or timing of any such limitations cannot be predicted. While we are exploring a number of alternatives, including the capture and storage of GHG emissions from new and existing power generation facilities, there is currently no demonstrated technology that controls the emissions of GHG from fossil-fueled generating plants. We are advancing more efficient technologies for power generation, including ultra-super-critical technology and IGCC, as authorized by our regulatory commissions. Carbon capture and storage or other GHG limiting technology, if successfully demonstrated, is likely to have a material impact on the cost of operating our fossil-fueled generating plants. We are also pursuing renewable sources of energy generation, energy efficiency measures, gridSMART load management investments and other improved transmission, distribution and energy storage methods to reduce overall GHG emissions from our operations. We will seek recovery of the costs from customers through our regulated rates and market prices of electricity.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, we manage other environmental concerns that we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on future net income, cash flows and possibly financial condition.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP’s Board of Directors and the Audit Committee reviews the disclosure relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.
Regulatory Accounting

Nature of Estimates Required: Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used: When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required: We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The change in unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $72 million, $47 million and $(19) million for the years ended December 31, 2008, 2007 and 2006, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $448 million and $376 million as of December 31, 2008 and 2007, respectively.

Assumptions and Approach Used: For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month’s billed KWH plus the prior month’s unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used: Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues on the Consolidated Balance Sheets.
Revenue Recognition – Accounting for Derivative Instruments

**Nature of Estimates Required:** We consider fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

**Assumptions and Approach Used:** We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We base credit adjustments on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

**Effect if Different Assumptions Used:** There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Note 11.

**Long-Lived Assets**

**Nature of Estimates Required:** In accordance with the requirements of SFAS 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” (SFAS 144) we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

**Assumptions and Approach Used:** The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.
Effect if Different Assumptions Used: In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 7 of the Notes to Consolidated Financial Statements, we made our best estimate of fair value using valuation methods based on the most current information at that time. We divested certain noncore assets and their sales values can vary from the recorded fair value as described in Note 7 of the Notes to Consolidated Financial Statements. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required: We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS 87, “Employers’ Accounting for Pensions”, SFAS 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions” and SFAS 158. See Note 8 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used: The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Rate of compensation increase
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used: The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

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Effect on December 31, 2008 Benefit Obligations

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<td>Health Care Cost Trend Rate</td>
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<td>Expected Return on Plan Assets</td>
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Effect on 2008 Periodic Cost

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<td>Expected Return on Plan Assets</td>
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N/A = Not Applicable
NEW ACCOUNTING PRONOUNCEMENTS

Adoption of New Accounting Pronouncements in 2008

We partially adopted SFAS 157 in 2008 and completed our adoption effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on our financial statements. See “SFAS 157 Fair Value Measurements” section of Note 11 for further information.

We adopted SFAS 159 “The Fair Value Option for Financial Assets and Financial Liabilities” effective January 1, 2008. The statement permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. At adoption, we did not elect the fair value option for any assets or liabilities.

The FASB issued SFAS 162 “The Hierarchy of Generally Accepted Accounting Principles” (SFAS 162), clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP. We adopted SFAS 162 with no impact on our financial statements.

The FASB ratified EITF 06-10 “Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements” a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.

We adopted EITF 06-11 “Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards” (EITF 06-11) effective January 1, 2008. The rule addressed the recognition of income tax benefits of dividends on employee share-based compensation. The adoption of this standard had an immaterial impact on our financial statements.

The FASB issued FSP SFAS 133-1 and FIN 45-4 “Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161.” Under the SFAS 133 requirements, the seller of a credit derivative shall disclose additional information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote. Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk. We adopted the standard effective December 31, 2008. The adoption of this standard had no impact on our financial statements but increased our guarantees disclosures in Note 6.

The FASB issued FSP SFAS 140-4 and FIN 46R-8 “Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities” amending SFAS 140 “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities” and FIN 46R “Consolidation of Variable Interest Entities.” The amendments required additional disclosure regarding transfers of financial assets and variable interest entities. We adopted the standards effective December 31, 2008. The adoption of these standards had no impact on our financial statements but increased our footnote disclosures for variable interest entities. See “Principles of Consolidation” section of Note 1.

FSP FIN 39-1 amends FIN 39 “Offsetting of Amounts Related to Certain Contracts” by replacing the interpretation’s definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period. This standard changed our method of netting certain balance sheet amounts. We adopted FIN 39-1 effective January 1, 2008.

See “Pronouncements Adopted in 2008” section of Note 2.
New Accounting Pronouncements Adopted During the First Quarter of 2009

The FASB issued SFAS 141R (revised “Business Combinations” 2007) improving financial reporting about business combinations and their effects. SFAS 141R can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments. We adopted SFAS 141R effective January 1, 2009. We will apply it to any future business combinations.

The FASB issued SFAS 160 “Noncontrolling Interest in Consolidated Financial Statements” (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. We adopted SFAS 160 retrospectively effective January 1, 2009. The adoption of this standard had an immaterial impact on our financial statements. Prior period financial statements in future filings will be comparable.

The FASB issued SFAS 161 “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard will increase our disclosure requirements related to derivative instruments and hedging activities in future reports. We adopted SFAS 161 effective January 1, 2009.

The FASB ratified EITF Issue No. 08-5 “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (EITF 08-5) a consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. We adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as we report fair value of long-term debt annually.

The FASB ratified EITF Issue No. 08-6 “Equity Method Investment Accounting Considerations” (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. We prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements.

We adopted FSP EITF 03-6-1 “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities” (EITF 03-6-1) effective January 1, 2009. The rule addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method. The adoption of this standard had an immaterial impact on our financial statements.

The FASB issued FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets” amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. We adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

Pronouncements Effective in the Future

The FASB issued FSP SFAS 132R-1 “Employers’ Disclosures about Postretirement Benefit Plan Assets” providing additional disclosure guidance for pension and OPEB plan assets. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk. This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report.
QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk and credit risk. In addition, we may be exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment, operating primarily within ERCOT, transacts in wholesale energy trading and marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts are financial derivatives, which will gradually settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, natural gas, coal and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President – AEP Utilities, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

The Committee of Chief Risk Officers (CCRO) adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. The following tables provide information on our risk management activities.
Mark-to-Market Risk Management Contract Net Assets (Liabilities)

The following two tables summarize the various mark-to-market (MTM) positions included on our balance sheet as of December 31, 2008 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet
December 31, 2008
(in millions)

<table>
<thead>
<tr>
<th></th>
<th>Utility Operations</th>
<th>Generation and Marketing</th>
<th>All Other</th>
<th>Sub-Total MTM Risk Management Contracts</th>
<th>MTM of Cash Flow and Fair Value Hedges</th>
<th>Collateral Deposits</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets</td>
<td>$ 189</td>
<td>$ 20</td>
<td>$ 19</td>
<td>$ 228</td>
<td>$ 33</td>
<td>(5)</td>
<td>$ 256</td>
</tr>
<tr>
<td>Noncurrent Assets</td>
<td>152</td>
<td>188</td>
<td>20</td>
<td>360</td>
<td>1</td>
<td>(6)</td>
<td>355</td>
</tr>
<tr>
<td>Total Assets</td>
<td>341</td>
<td>208</td>
<td>39</td>
<td>588</td>
<td>34</td>
<td>(11)</td>
<td>611</td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>(89)</td>
<td>(14)</td>
<td>(24)</td>
<td>(127)</td>
<td>(26)</td>
<td>19</td>
<td>(134)</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>(77)</td>
<td>(90)</td>
<td>(22)</td>
<td>(189)</td>
<td>(5)</td>
<td>24</td>
<td>(170)</td>
</tr>
<tr>
<td>Total Liabilities</td>
<td>(166)</td>
<td>(104)</td>
<td>(46)</td>
<td>(316)</td>
<td>(31)</td>
<td>43</td>
<td>(304)</td>
</tr>
</tbody>
</table>

Total MTM Derivative Contract Net Assets (Liabilities) $ 175  $ 104  $ (7)  $ 272  $ 3  $ 32  $ 307

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2008
(in millions)

<table>
<thead>
<tr>
<th></th>
<th>Utility Operations</th>
<th>Generation and Marketing</th>
<th>All Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2007</td>
<td>$ 156</td>
<td>$ 43</td>
<td>(8)</td>
<td>$ 191</td>
</tr>
<tr>
<td>(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period</td>
<td>(55)</td>
<td>11</td>
<td>2</td>
<td>(42)</td>
</tr>
<tr>
<td>Fair Value of New Contracts at Inception When Entered During the Period (a)</td>
<td>4</td>
<td>33</td>
<td>-</td>
<td>37</td>
</tr>
<tr>
<td>Net Option Premiums Paid (Received) for Unexercised or Unexpired Option Contracts Ended During the Period</td>
<td>-</td>
<td>2</td>
<td>-</td>
<td>2</td>
</tr>
<tr>
<td>Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)</td>
<td>4</td>
<td>14</td>
<td>-</td>
<td>18</td>
</tr>
<tr>
<td>Changes in Fair Value Due to Market Fluctuations During the Period (c)</td>
<td>14</td>
<td>1</td>
<td>(1)</td>
<td>14</td>
</tr>
<tr>
<td>Changes in Fair Value Allocated to Regulated Jurisdictions (d)</td>
<td>52</td>
<td></td>
<td>-</td>
<td>52</td>
</tr>
<tr>
<td>Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2008</td>
<td>$ 175</td>
<td>$ 104</td>
<td>(7)</td>
<td>272</td>
</tr>
<tr>
<td>Net Cash Flow and Fair Value Hedge Contracts</td>
<td>3</td>
<td></td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>Collateral Deposits</td>
<td></td>
<td></td>
<td></td>
<td>32</td>
</tr>
<tr>
<td>Ending Net Risk Management Assets at December 31, 2008</td>
<td>$ 307</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP’s credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) “Change in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)

The following table presents the maturity, by year, of our net assets/liabilities, to give an indication of when these MTM amounts will settle and generate cash:

<table>
<thead>
<tr>
<th>Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)</th>
<th>Fair Value of Contracts as of December 31, 2008 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Operations</td>
<td></td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>$ (9)</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>74</td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td>21</td>
</tr>
<tr>
<td>Total</td>
<td>86</td>
</tr>
<tr>
<td>Generation and Marketing</td>
<td></td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>(7)</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>9</td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td>6</td>
</tr>
<tr>
<td>All Other</td>
<td></td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>-</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>(5)</td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td>(5)</td>
</tr>
<tr>
<td>Total</td>
<td></td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>(16)</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>78</td>
</tr>
<tr>
<td>Level 3 (c) (d)</td>
<td>25</td>
</tr>
<tr>
<td>Total</td>
<td>87</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (e)</td>
<td>14</td>
</tr>
<tr>
<td>Total MTM Risk Management Contract Net Assets (Liabilities)</td>
<td>$ 101</td>
</tr>
</tbody>
</table>

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

(d) A significant portion of the total volumetric position within the consolidated Level 3 balance has been economically hedged.

(e) Dedesigned Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized within Utility Operations Revenues over the remaining life of the contracts.

(f) There is mark-to-market value of $22 million in individual periods beyond 2013. $12 million of this mark-to-market value is in 2014, $4 million is in 2015, $3 million is in 2016 and $3 million is in 2017.
Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Consolidated Balance Sheets

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may use various commodity derivative instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

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

We use foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedges. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2007 to December 31, 2008. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables. All amounts are presented net of related income taxes.

### Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges

*Year Ended December 31, 2008*

<table>
<thead>
<tr>
<th></th>
<th>Power</th>
<th>Interest Rate and Foreign Currency</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Beginning Balance in AOCI, December 31, 2007</strong></td>
<td>$1</td>
<td>$25</td>
<td>$26</td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>6</td>
<td>(9)</td>
<td>(3)</td>
</tr>
<tr>
<td>Reclassifications from AOCI for Cash Flow Hedges Settled</td>
<td>2</td>
<td>5</td>
<td>7</td>
</tr>
<tr>
<td><strong>Ending Balance in AOCI, December 31, 2008</strong></td>
<td>$7</td>
<td>$29</td>
<td>$22</td>
</tr>
<tr>
<td>After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months</td>
<td>$7</td>
<td>$(5)</td>
<td>$2</td>
</tr>
</tbody>
</table>
Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been originated. We use Moody’s Investors Service, Standard & Poor’s and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody’s to estimate probability of default that corresponds to an implied external agency credit rating. Based on our analysis, we set appropriate risk parameters for each internally-graded counterparty. We may also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties in order to mitigate credit risk.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At December 31, 2008, our credit exposure net of collateral to sub investment grade counterparties was approximately 7.1%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2008, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

<table>
<thead>
<tr>
<th>Counterparty Credit Quality</th>
<th>Exposure Before Credit Collateral (in millions, except number of counterparties)</th>
<th>Credit Collateral</th>
<th>Net Exposure</th>
<th>Number of Counterparties &gt;10% of Net Exposure</th>
<th>Net Exposure of Counterparties &gt;10%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investment Grade</td>
<td>$622</td>
<td>$25</td>
<td>$597</td>
<td>2</td>
<td>$178</td>
</tr>
<tr>
<td>Split Rating</td>
<td>9</td>
<td>-</td>
<td>9</td>
<td>2</td>
<td>9</td>
</tr>
<tr>
<td>Noninvestment Grade</td>
<td>17</td>
<td>4</td>
<td>13</td>
<td>1</td>
<td>12</td>
</tr>
<tr>
<td>No External Ratings:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Internal Investment Grade</td>
<td>103</td>
<td>-</td>
<td>103</td>
<td>2</td>
<td>56</td>
</tr>
<tr>
<td>Internal Noninvestment Grade</td>
<td>42</td>
<td>-</td>
<td>42</td>
<td>2</td>
<td>29</td>
</tr>
<tr>
<td>Total as of December 31, 2008</td>
<td>$793</td>
<td>$29</td>
<td>$764</td>
<td>9</td>
<td>$284</td>
</tr>
<tr>
<td>Total as of December 31, 2007</td>
<td>$673</td>
<td>$42</td>
<td>$631</td>
<td>6</td>
<td>$74</td>
</tr>
</tbody>
</table>

Collateral Triggering Events

Under a limited number of counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. Our risk management organization assesses the appropriateness of these collateral triggering items in ongoing contract negotiations. We believe that a downgrade below investment grade is unlikely. As of December 31, 2008, we would have been required to post $174 million of collateral if our credit ratings had declined below investment grade of which $161 million is attributable to our RTO and ISO activities.
VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2008, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the years ended:

<table>
<thead>
<tr>
<th>VaR Model</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>End</td>
<td>High</td>
<td>Average</td>
</tr>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>$-</td>
<td>$3</td>
<td>$1</td>
</tr>
</tbody>
</table>

We back-test our VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Our backtesting results show that our actual performance exceeded VaR far fewer than once every 20 trading days. As a result, we believe our VaR calculation is conservative.

As our VaR calculation captures recent price moves, we also perform regular stress testing of the portfolio to understand our exposure to extreme price moves. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translated into the largest potential mark-to-market loss. We then research the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on our debt portfolio is $86 million.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in common shareholders’ equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 8 to the consolidated financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2008, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2008 of the Company and our report dated February 27, 2009 expressed an unqualified opinion on those financial statements and included an explanatory paragraph concerning the Company’s adoption of new accounting pronouncements in 2007 and 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15 (f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of AEP’s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, AEP’s internal control over financial reporting was effective as of December 31, 2008.

AEP’s independent registered public accounting firm has issued an attestation report on AEP’s internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.
## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2008, 2007 and 2006
(in millions, except per-share and share amounts)

### REVENUES

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Operations</td>
<td>$13,326</td>
<td>$12,101</td>
<td>$12,066</td>
</tr>
<tr>
<td>Other</td>
<td>1,114</td>
<td>1,279</td>
<td>556</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>14,440</strong></td>
<td><strong>13,380</strong></td>
<td><strong>12,622</strong></td>
</tr>
</tbody>
</table>

### EXPENSES

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel and Other Consumables Used for Electric Generation</td>
<td>4,474</td>
<td>3,829</td>
<td>3,817</td>
</tr>
<tr>
<td>Purchased Electricity for Resale</td>
<td>1,281</td>
<td>1,138</td>
<td>856</td>
</tr>
<tr>
<td>Other Operation and Maintenance</td>
<td>3,925</td>
<td>3,867</td>
<td>3,639</td>
</tr>
<tr>
<td>Gain on Disposition of Assets, Net</td>
<td>(16)</td>
<td>(41)</td>
<td>(69)</td>
</tr>
<tr>
<td>Asset Impairments and Other Related Charges</td>
<td>(255)</td>
<td>-</td>
<td>209</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>1,483</td>
<td>1,513</td>
<td>1,467</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>761</td>
<td>755</td>
<td>737</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>11,653</strong></td>
<td><strong>11,061</strong></td>
<td><strong>10,656</strong></td>
</tr>
</tbody>
</table>

### OPERATING INCOME

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,787</strong></td>
<td><strong>2,319</strong></td>
<td><strong>1,966</strong></td>
</tr>
</tbody>
</table>

### Other Income:

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest and Investment Income</td>
<td>57</td>
<td>51</td>
<td>99</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>83</td>
<td>51</td>
<td>114</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>45</td>
<td>33</td>
<td>30</td>
</tr>
<tr>
<td>Gain on Disposition of Equity Investments, Net</td>
<td>-</td>
<td>47</td>
<td>3</td>
</tr>
</tbody>
</table>

### INTEREST AND OTHER CHARGES

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest Expense</td>
<td>958</td>
<td>841</td>
<td>732</td>
</tr>
<tr>
<td>Preferred Stock Dividend Requirements of Subsidiaries</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>961</strong></td>
<td><strong>844</strong></td>
<td><strong>735</strong></td>
</tr>
</tbody>
</table>

### INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax Expense</td>
<td>642</td>
<td>516</td>
<td>485</td>
</tr>
<tr>
<td>Minority Interest Expense</td>
<td>4</td>
<td>3</td>
<td>3</td>
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<tr>
<td>Equity Earnings of Unconsolidated Subsidiaries</td>
<td>3</td>
<td>6</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,011</strong></td>
<td><strong>1,657</strong></td>
<td><strong>1,477</strong></td>
</tr>
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</table>

### INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,368</strong></td>
<td><strong>1,144</strong></td>
<td><strong>992</strong></td>
</tr>
</tbody>
</table>

### DISCONTINUED OPERATIONS, NET OF TAX

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>12</strong></td>
<td><strong>24</strong></td>
<td><strong>10</strong></td>
</tr>
</tbody>
</table>

### EXTRAORDINARY LOSS, NET OF TAX

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,380</strong></td>
<td><strong>1,168</strong></td>
<td><strong>1,002</strong></td>
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</tbody>
</table>

### NET INCOME

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>$1,380</strong></td>
<td><strong>$1,089</strong></td>
<td><strong>$1,002</strong></td>
</tr>
</tbody>
</table>

### WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>402,083,847</strong></td>
<td><strong>398,784,745</strong></td>
<td><strong>394,219,523</strong></td>
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</table>

### BASIC EARNINGS (LOSS) PER SHARE

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Before Discontinued Operations and Extraordinary Loss</td>
<td>$3.40</td>
<td>$2.87</td>
<td>$2.52</td>
</tr>
<tr>
<td>Discontinued Operations, Net of Tax</td>
<td>0.03</td>
<td>0.06</td>
<td>0.02</td>
</tr>
<tr>
<td>Income Before Extraordinary Loss</td>
<td>3.43</td>
<td>2.93</td>
<td>2.54</td>
</tr>
<tr>
<td>Extraordinary Loss, Net of Tax</td>
<td>-</td>
<td>(0.20)</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Basic Earnings Per Share</strong></td>
<td><strong>$3.43</strong></td>
<td><strong>$2.73</strong></td>
<td><strong>$2.54</strong></td>
</tr>
</tbody>
</table>

### WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>403,640,708</strong></td>
<td><strong>400,198,799</strong></td>
<td><strong>396,483,464</strong></td>
</tr>
</tbody>
</table>

### DILUTED EARNINGS (LOSS) PER SHARE

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Before Discontinued Operations and Extraordinary Loss</td>
<td>$3.39</td>
<td>$2.86</td>
<td>$2.50</td>
</tr>
<tr>
<td>Discontinued Operations, Net of Tax</td>
<td>0.03</td>
<td>0.06</td>
<td>0.03</td>
</tr>
<tr>
<td>Income Before Extraordinary Loss</td>
<td>3.42</td>
<td>2.92</td>
<td>2.53</td>
</tr>
<tr>
<td>Extraordinary Loss, Net of Tax</td>
<td>-</td>
<td>(0.20)</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Diluted Earnings Per Share</strong></td>
<td><strong>$3.42</strong></td>
<td><strong>$2.72</strong></td>
<td><strong>$2.53</strong></td>
</tr>
</tbody>
</table>

### CASH DIVIDENDS PAID PER SHARE

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td><strong>$1.64</strong></td>
<td><strong>$1.58</strong></td>
<td><strong>$1.50</strong></td>
</tr>
</tbody>
</table>

See Notes to Consolidated Financial Statements.
## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

### CONSOLIDATED BALANCE SHEETS

#### ASSETS

**December 31, 2008 and 2007**

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CURRENT ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$ 411</td>
<td>$ 178</td>
</tr>
<tr>
<td>Other Temporary Investments</td>
<td>327</td>
<td>365</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Customers</td>
<td>569</td>
<td>730</td>
</tr>
<tr>
<td>- Accrued Unbilled Revenues</td>
<td>449</td>
<td>379</td>
</tr>
<tr>
<td>- Miscellaneous</td>
<td>90</td>
<td>60</td>
</tr>
<tr>
<td>- Allowance for Uncollectible Accounts</td>
<td>(42)</td>
<td>(52)</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>1,066</td>
<td>1,117</td>
</tr>
<tr>
<td>Fuel</td>
<td>634</td>
<td>436</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>539</td>
<td>531</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>256</td>
<td>271</td>
</tr>
<tr>
<td>Regulatory Asset for Under-Recovered Fuel Costs</td>
<td>284</td>
<td>11</td>
</tr>
<tr>
<td>Margin Deposits</td>
<td>86</td>
<td>47</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>172</td>
<td>70</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>3,775</td>
<td>3,026</td>
</tr>
<tr>
<td><strong>PROPERTY, PLANT AND EQUIPMENT</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Production</td>
<td>21,242</td>
<td>20,233</td>
</tr>
<tr>
<td>- Transmission</td>
<td>7,938</td>
<td>7,392</td>
</tr>
<tr>
<td>- Distribution</td>
<td>12,816</td>
<td>12,056</td>
</tr>
<tr>
<td>- Other (including coal mining and nuclear fuel)</td>
<td>3,741</td>
<td>3,445</td>
</tr>
<tr>
<td>- Construction Work in Progress</td>
<td>3,973</td>
<td>3,019</td>
</tr>
<tr>
<td>Total</td>
<td>49,710</td>
<td>46,145</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>16,723</td>
<td>16,275</td>
</tr>
<tr>
<td><strong>TOTAL - NET</strong></td>
<td>32,987</td>
<td>29,870</td>
</tr>
<tr>
<td><strong>OTHER NONCURRENT ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulatory Assets</td>
<td>3,783</td>
<td>2,199</td>
</tr>
<tr>
<td>Securitized Transition Assets</td>
<td>2,040</td>
<td>2,108</td>
</tr>
<tr>
<td>Spent Nuclear Fuel and Decommissioning Trusts</td>
<td>1,260</td>
<td>1,347</td>
</tr>
<tr>
<td>Goodwill</td>
<td>76</td>
<td>76</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>355</td>
<td>319</td>
</tr>
<tr>
<td>Employee Benefits and Pension Assets</td>
<td>3</td>
<td>486</td>
</tr>
<tr>
<td>Deferred Charges and Other</td>
<td>876</td>
<td>888</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>8,393</td>
<td>7,423</td>
</tr>
</tbody>
</table>

**TOTAL ASSETS**

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$ 45,155</td>
<td>$ 40,319</td>
</tr>
</tbody>
</table>

*See Notes to Consolidated Financial Statements.*
# AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
## CONSOLIDATED BALANCE SHEETS
### LIABILITIES AND SHAREHOLDERS’ EQUITY
#### December 31, 2008 and 2007

<table>
<thead>
<tr>
<th>Current Liabilities (in millions)</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accounts Payable</td>
<td>$1,297</td>
<td>$1,324</td>
</tr>
<tr>
<td>Short-term Debt</td>
<td>1,976</td>
<td>660</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year</td>
<td>447</td>
<td>792</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>134</td>
<td>240</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>254</td>
<td>301</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>634</td>
<td>601</td>
</tr>
<tr>
<td>Accrued Interest</td>
<td>270</td>
<td>235</td>
</tr>
<tr>
<td>Other</td>
<td>1,285</td>
<td>1,008</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>6,297</td>
<td>5,161</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Noncurrent Liabilities (in millions)</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Debt</td>
<td>15,536</td>
<td>14,202</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>170</td>
<td>188</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>5,128</td>
<td>4,730</td>
</tr>
<tr>
<td>Regulatory Liabilities and Deferred Investment Tax Credits</td>
<td>2,789</td>
<td>2,952</td>
</tr>
<tr>
<td>Asset Retirement Obligations</td>
<td>1,154</td>
<td>1,075</td>
</tr>
<tr>
<td>Employee Benefits and Pension Obligations</td>
<td>2,184</td>
<td>712</td>
</tr>
<tr>
<td>Deferred Credits and Other</td>
<td>1,143</td>
<td>1,159</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>28,104</td>
<td>25,018</td>
</tr>
</tbody>
</table>

### Total Liabilities
- **2008**: $34,401
- **2007**: $30,179

#### Cumulative Preferred Stock Not Subject to Mandatory Redemption
- **2008**: 61
- **2007**: 61

#### Commitments and Contingencies (Note 6)

#### Common Shareholders’ Equity

<table>
<thead>
<tr>
<th>Common Stock Par Value $6.50:</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shares Authorized (in millions)</td>
<td>600,000,000</td>
<td>600,000,000</td>
</tr>
<tr>
<td>Shares Issued</td>
<td>426,321,248</td>
<td>421,926,696</td>
</tr>
<tr>
<td>(20,249,992 shares and 21,499,992 shares were held in treasury at December 31, 2008 and 2007, respectively)</td>
<td>2,771</td>
<td>2,743</td>
</tr>
<tr>
<td>Paid-in Capital</td>
<td>4,527</td>
<td>4,352</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>3,847</td>
<td>3,138</td>
</tr>
<tr>
<td>Accumulated Other Comprehensive Income (Loss)</td>
<td>(452)</td>
<td>(154)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>10,693</td>
<td>10,079</td>
</tr>
</tbody>
</table>

### Total Liabilities and Shareholders’ Equity
- **2008**: $45,155
- **2007**: $40,319

See Notes to Consolidated Financial Statements.
AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006
(in millions)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>OPERATING ACTIVITIES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$ 1,380</td>
<td>$ 1,089</td>
<td>$ 1,002</td>
</tr>
<tr>
<td>Less: Discontinued Operations, Net of Tax</td>
<td>(12)</td>
<td>(24)</td>
<td>(10)</td>
</tr>
<tr>
<td><strong>Income Before Discontinued Operations</strong></td>
<td>1,368</td>
<td>1,065</td>
<td>992</td>
</tr>
<tr>
<td>Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>1,483</td>
<td>1,513</td>
<td>1,467</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>498</td>
<td>76</td>
<td>24</td>
</tr>
<tr>
<td>Provision for Revenue Refund</td>
<td>149</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Extraordinary Loss, Net of Tax</td>
<td>-</td>
<td>79</td>
<td>-</td>
</tr>
<tr>
<td>Asset Impairments, Investment Value Losses and Other Related Charges</td>
<td>-</td>
<td>-</td>
<td>209</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>(83)</td>
<td>(51)</td>
<td>(114)</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>(45)</td>
<td>(33)</td>
<td>(30)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>(140)</td>
<td>3</td>
<td>(191)</td>
</tr>
<tr>
<td>Amortization of Nuclear Fuel</td>
<td>88</td>
<td>65</td>
<td>50</td>
</tr>
<tr>
<td>Deferred Property Taxes</td>
<td>(13)</td>
<td>(26)</td>
<td>(14)</td>
</tr>
<tr>
<td>Fuel Over/Under-Recovery, Net</td>
<td>(272)</td>
<td>(117)</td>
<td>182</td>
</tr>
<tr>
<td>Gain on Sales of Assets and Equity Investments, Net</td>
<td>(17)</td>
<td>(88)</td>
<td>(72)</td>
</tr>
<tr>
<td>Change in Noncurrent Liability for NSR Settlement</td>
<td>-</td>
<td>58</td>
<td>-</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>(199)</td>
<td>(98)</td>
<td>15</td>
</tr>
<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>(34)</td>
<td>66</td>
<td>(1)</td>
</tr>
<tr>
<td><strong>Changes in Certain Components of Working Capital:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts Receivable, Net</td>
<td>71</td>
<td>(113)</td>
<td>177</td>
</tr>
<tr>
<td>Fuel, Materials and Supplies</td>
<td>(183)</td>
<td>16</td>
<td>(187)</td>
</tr>
<tr>
<td>Margin Deposits</td>
<td>(40)</td>
<td>50</td>
<td>(13)</td>
</tr>
<tr>
<td>Accounts Payable</td>
<td>(94)</td>
<td>(21)</td>
<td>56</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>(48)</td>
<td>49</td>
<td>36</td>
</tr>
<tr>
<td>Accrued Taxes, Net</td>
<td>4</td>
<td>(90)</td>
<td>128</td>
</tr>
<tr>
<td>Accrued Interest</td>
<td>30</td>
<td>11</td>
<td>4</td>
</tr>
<tr>
<td>Other Current Assets</td>
<td>(29)</td>
<td>(11)</td>
<td>17</td>
</tr>
<tr>
<td>Other Current Liabilities</td>
<td>82</td>
<td>(15)</td>
<td>(3)</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Operating Activities</strong></td>
<td>2,576</td>
<td>2,388</td>
<td>2,732</td>
</tr>
<tr>
<td><strong>INVESTING ACTIVITIES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Expenditures</td>
<td>(3,800)</td>
<td>(3,556)</td>
<td>(3,528)</td>
</tr>
<tr>
<td>Change in Other Temporary Investments, Net</td>
<td>45</td>
<td>(114)</td>
<td>(33)</td>
</tr>
<tr>
<td>Purchases of Investment Securities</td>
<td>(1,922)</td>
<td>(11,086)</td>
<td>(18,359)</td>
</tr>
<tr>
<td>Sales of Investment Securities</td>
<td>1,917</td>
<td>11,213</td>
<td>18,080</td>
</tr>
<tr>
<td>Acquisitions of Nuclear Fuel</td>
<td>(192)</td>
<td>74</td>
<td>(89)</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(160)</td>
<td>(512)</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>90</td>
<td>222</td>
<td>186</td>
</tr>
<tr>
<td>Other</td>
<td>(5)</td>
<td>(14)</td>
<td>-</td>
</tr>
<tr>
<td><strong>Net Cash Flows Used for Investing Activities</strong></td>
<td>(4,027)</td>
<td>(3,921)</td>
<td>(3,743)</td>
</tr>
<tr>
<td><strong>FINANCING ACTIVITIES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Issuance of Common Stock</td>
<td>159</td>
<td>144</td>
<td>99</td>
</tr>
<tr>
<td>Issuance of Long-term Debt</td>
<td>2,774</td>
<td>2,546</td>
<td>3,359</td>
</tr>
<tr>
<td>Change in Short-term Debt, Net</td>
<td>1,316</td>
<td>642</td>
<td>7</td>
</tr>
<tr>
<td>Retirement of Long-term Debt</td>
<td>(1,824)</td>
<td>(1,286)</td>
<td>(1,946)</td>
</tr>
<tr>
<td>Proceeds from Nuclear Fuel Sale/Leaseback</td>
<td>-</td>
<td>85</td>
<td>-</td>
</tr>
<tr>
<td>Principal Payments for Capital Lease Obligations</td>
<td>(97)</td>
<td>(67)</td>
<td>(63)</td>
</tr>
<tr>
<td>Dividends Paid on Common Stock</td>
<td>(660)</td>
<td>(630)</td>
<td>(591)</td>
</tr>
<tr>
<td>Dividends Paid on Cumulative Preferred Stock</td>
<td>(3)</td>
<td>(3)</td>
<td>(3)</td>
</tr>
<tr>
<td>Other</td>
<td>19</td>
<td>(21)</td>
<td>49</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Financing Activities</strong></td>
<td>1,684</td>
<td>1,410</td>
<td>911</td>
</tr>
<tr>
<td>Net Increase (Decrease) in Cash and Cash Equivalents</td>
<td>233</td>
<td>(123)</td>
<td>(100)</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
<td>178</td>
<td>301</td>
<td>401</td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at End of Period</strong></td>
<td>$ 411</td>
<td>$ 178</td>
<td>$ 301</td>
</tr>
</tbody>
</table>

See Notes to Consolidated Financial Statements.
# AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

## CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS’ EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2008, 2007, and 2006

(in millions)

<table>
<thead>
<tr>
<th>Shares</th>
<th>Common Stock</th>
<th>Paid-in Capital</th>
<th>Retained Earnings</th>
<th>Other Comprehensive Income (Loss)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>415</td>
<td>$ 2,699</td>
<td>$ 4,131</td>
<td>$ 2,285</td>
<td>(27)</td>
<td>$ 9,088</td>
</tr>
</tbody>
</table>

**Issuance of Common Stock**
- 3   19  80   99

**Common Stock Dividends**
- (591) (591)

**Other**
- 10

**TOTAL**
- 8,606

### COMPREHENSIVE INCOME

**Other Comprehensive Income (Loss), Net of Taxes:**
- Cash Flow Hedges, Net of Tax of $11
- Securities Available for Sale, Net of Tax of $0
- Minimum Pension Liability, Net of Tax of $1

**NET INCOME**
- 1,002

**TOTAL COMPREHENSIVE INCOME**
- 1,024

**Minimum Pension Liability Elimination, Net of Tax of $9**
- 17

**SFAS 158 Adoption, Net of Tax of $126**
- (235)

**DECEMBER 31, 2006**
- 418   2,718   4,221   2,696   (223)  9,412

**FIN 48 Adoption, Net of Tax**
- (17)

**Issuance of Common Stock**
- 4   25   119   144

**Reissuance of Treasury Shares**
- 40

**Common Stock Dividends**
- (630) (630)

**Other**
- 12

**TOTAL**
- 8,921

### COMPREHENSIVE INCOME

**Other Comprehensive Income (Loss), Net of Taxes:**
- Cash Flow Hedges, Net of Tax of $10
- Securities Available for Sale, Net of Tax of $1
- SFAS 158 Adoption Costs Established as a Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6
- Pension and OPEB Funded Status, Net of Tax of $42

**NET INCOME**
- 1,089

**TOTAL COMPREHENSIVE INCOME**
- 1,158

**EITF 06-10 Adoption, Net of Tax of $6**
- (10)

**SFAS 157 Adoption, Net of Tax of $0**
- (1)

**Issuance of Common Stock**
- 4   28   131   159

**Reissuance of Treasury Shares**
- 40

**Common Stock Dividends**
- (660) (660)

**Other**
- 4

**TOTAL**
- 9,611

### COMPREHENSIVE INCOME

**Other Comprehensive Income (Loss), Net of Taxes:**
- Cash Flow Hedges, Net of Tax of $2
- Securities Available for Sale, Net of Tax of $9
- Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7
- Pension and OPEB Funded Status, Net of Tax of $161

**NET INCOME**
- 1,380

**TOTAL COMPREHENSIVE INCOME**
- 1,082

**EITF 06-10 Adoption, Net of Tax of $6**
- (10)

**SFAS 157 Adoption, Net of Tax of $0**
- (1)

**Issuance of Common Stock**
- 4   28   131   159

**Reissuance of Treasury Shares**
- 40

**Common Stock Dividends**
- (660) (660)

**Other**
- 4

**TOTAL**
- 9,611

**See Notes to Consolidated Financial Statements.**
1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements and Extraordinary Item
3. Goodwill and Other Intangible Assets
4. Rate Matters
5. Effects of Regulation
6. Commitments, Guarantees and Contingencies
7. Acquisitions, Dispositions, Discontinued Operations and Impairments
8. Benefit Plans
9. Nuclear
10. Business Segments
11. Derivatives, Hedging and Fair Value Measurements
12. Income Taxes
13. Leases
14. Financing Activities
15. Stock-Based Compensation
16. Property, Plant and Equipment
17. Unaudited Quarterly Financial Information
1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with WPCo and KGPCo, provide only transmission and distribution services. TNC is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a non-utility affiliate. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries’ rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The state regulatory commissions approve retail rates and regulate the retail services and operations of the utility subsidiaries for the generation and supply of power, a majority of transmission energy delivery services and distribution services. The FERC regulates our affiliated transactions, including AEPSC intercompany service billing which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliates statutes.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have “market power” in the region where the transaction occurs. We enter into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. Our wholesale power transactions in the SPP region are cost-based due to SWEPCo and PSO having market power in the SPP region.

The FERC also regulates, on a cost basis, our wholesale transmission service and rates except in Texas. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo’s and OPCo’s retail rates in Ohio, APCo’s retail rates in Virginia, I&M’s retail rates in Michigan and TCC’s and TNC’s retail rates in Texas are unbundled. Therefore, CSPCo’s and OPCo’s retail transmission rates are based on the FERC’s Open Access Transmission Tariff (OATT) rates that are cost-based. Although APCo’s retail rates in Virginia, I&M’s retail rates in Michigan and TCC’s and TNC’s retail rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Starting in 2009, APCo may file, and the Virginia SCC shall approve, a rate adjustment clause that passes through charges associated with the FERC’s OATT rates to APCo’s Virginia retail customers. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Equalization Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.
The state regulatory commissions regulate all of our retail public utility services/operations (generation/power supply, transmission and distribution operations) and rates except in Ohio and the ERCOT region of Texas. Our retail generation/power supply operations and rates for CSPCo and OPCo in Ohio are no longer cost-based regulated. These rates were subject to RSPs through December 31, 2008. The PUCO extended these rates until they issue a ruling on the ESPs or the end of the February 2009 billing cycle, whichever comes first. The ESP rates are under recently enacted legislation, which continues the concept of increasing rates over time to approach market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing. AEP has no Texas jurisdictional retail generation/power supply operations other than a minor supply operation through a commercial and industrial customer REP. In 2007, the Virginia legislation ended a transition to market-based rates and returned APCo to cost-based regulation. See Note 4 for further information on restructuring legislation and its effects on AEP in Ohio, Texas and Michigan.

Both the FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

**Principles of Consolidation**

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled and which we are not the primary beneficiary of the entity, that are 50% or less owned are accounted for using the equity method of accounting and recorded as Deferred Charges and Other on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. For years, we have had ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of variability of the VIE we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments have been consistently applied and that there are no other reasonable judgments or assumptions that would have resulted in a different conclusion.

We are the primary beneficiary of Sabine, DHLC, JMG and a protected cell of EIS. We hold a variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series). In addition, we have not provided financial or other support that was not previously contractually required to any VIE.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine’s only customer. SWEPCo has guaranteed the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee which is included in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income. Based on these facts, management has concluded SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo’s total billings from Sabine for the years ended December 31, 2008 and 2007 were $110 million and $95 million, respectively. See the tables below for the classification of Sabine’s assets and liabilities on our Consolidated Balance Sheets.
DHL is a wholly-owned subsidiary of SWEPCo. DHL is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHL’s debt. The creditors of DHL have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHL. SWEPCo’s total billings from DHL for the years ended December 31, 2008 and 2007 were $44 million and $35 million, respectively. These billings are included in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income. See the tables below for the classification of DHL's assets and liabilities on our Consolidated Balance Sheets.

OPCo has a lease agreement with JMG to finance OPCo’s FGD system installed on OPCo’s Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo’s lease payments are the only form of repayment associated with JMG’s debt obligations even though OPCo does not guarantee JMG’s debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded OPCo is the primary beneficiary and is required to consolidate JMG. OPCo’s total billings from JMG for the years ended December 31, 2008 and 2007 were $57 million and $46 million, respectively. See the tables below for the classification of JMG’s assets and liabilities on our Consolidated Balance Sheets.

EIS is a captive insurance company with multiple protected cells in which our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP system is essentially this EIS cell’s only participant, but allow certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on the structure of the protected cell, we have concluded that we are the primary beneficiary and that we are required to consolidate the protected cell. Our insurance premium payments to EIS for the years ended December 31, 2008 and 2007 were $28 million and $26 million, respectively. See the tables below for the classification of EIS’s assets and liabilities on our Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

### AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

#### VARIABLE INTEREST ENTITIES

**December 31, 2008**

<table>
<thead>
<tr>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASSETS</td>
</tr>
<tr>
<td>SWEPCo Sabine</td>
</tr>
<tr>
<td>Current Assets</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
</tr>
<tr>
<td>Other Noncurrent Assets</td>
</tr>
<tr>
<td>Total Assets</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>LIABILITIES AND SHAREHOLDERS’ EQUITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Liabilities</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
</tr>
<tr>
<td>Common Shareholders’ Equity</td>
</tr>
<tr>
<td>Total Liabilities and Shareholders’ Equity</td>
</tr>
</tbody>
</table>
AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2007
(in millions)

<table>
<thead>
<tr>
<th>ASSETS</th>
<th>SWEPCo Sabine</th>
<th>SWEPCo DHLIC</th>
<th>OPCo JMG</th>
<th>EIS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets</td>
<td>$24</td>
<td>$29</td>
<td>$5</td>
<td>-</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>97</td>
<td>41</td>
<td>443</td>
<td>-</td>
</tr>
<tr>
<td>Other Noncurrent Assets</td>
<td>25</td>
<td>13</td>
<td>1</td>
<td>21</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$146</td>
<td>$83</td>
<td>$449</td>
<td>$21</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>LIABILITIES AND SHAREHOLDERS' EQUITY</th>
<th>SWEPCo Sabine</th>
<th>SWEPCo DHLIC</th>
<th>OPCo JMG</th>
<th>EIS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Liabilities</td>
<td>$14</td>
<td>$26</td>
<td>$98</td>
<td>-</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>130</td>
<td>54</td>
<td>335</td>
<td>-</td>
</tr>
<tr>
<td>Common Shareholders’ Equity</td>
<td>2</td>
<td>3</td>
<td>16</td>
<td>21</td>
</tr>
<tr>
<td><strong>Total Liabilities and Shareholders’ Equity</strong></td>
<td>$146</td>
<td>$83</td>
<td>$449</td>
<td>$21</td>
</tr>
</tbody>
</table>

In September 2007, we and Allegheny (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the “Ohio Series,” the “West Virginia Series (PATH-WV),” both owned equally by AYE and us and the “Allegheny Series” which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The “Ohio Series” does not include the same provision that makes PATH-WV a VIE. The other series are not considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE’s subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series will be consistent with other regulated utilities and the entities are designed to maintain this financing structure. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. Currently the entity has no debt financing. The likelihood of such a loss is remote since the FERC approved PATH-WV’s request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV as of December 31, 2008 was:

<table>
<thead>
<tr>
<th>As Reported on the Consolidated Balance Sheet</th>
<th>Maximum Exposure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Contribution from Parent $</td>
<td>4 $</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>2</td>
</tr>
<tr>
<td><strong>Total Investment in PATH-WV</strong></td>
<td>$6</td>
</tr>
</tbody>
</table>

We record our investment in PATH-WV in Deferred Charges and Other on our Consolidated Balance Sheets. As of December 31, 2007, we did not make a capital contribution to PATH-WV and therefore had no retained earnings.

A-59
As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required restructuring and a transition to customer choice and market-based rates, we discontinued the application of SFAS 71, regulatory accounting, for the generation portion of our business as follows: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000 and in Texas for TCC and TNC and the Texas portion of SWEPCo in September 1999. In 2007, the Virginia legislature amended its restructuring legislation to provide for the re-regulation of generation and supply business and rates on a cost basis. SFAS 101, “Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71” requires the recognition of an impairment of stranded regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities pursuant to SFAS 71. Such impairments and adjustments arising from the discontinuance or reapplication of SFAS 71 are classified by SFAS 101 as an extraordinary item. Consistent with SFAS 101, APCo recorded an extraordinary reduction in earnings and shareholder’s equity from the reapplication of SFAS 71 regulatory accounting in 2007 resulting from the re-regulation of their generation and supply rates on a cost basis.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management’s evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other) are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For the Utility Operations segment, normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and most nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Gains and losses are recorded for any retirements in the AEP River Operations and Generation and Marketing segments. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.
The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

**Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization**

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and Texas, effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, “Capitalization of Interest Costs.”

**Valuation of Nonderivative Financial Instruments**

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

**Cash and Cash Equivalents**

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

**Other Temporary Investments**

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell insurance company and funds held by trustees primarily for the payment of debt.

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

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

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. During 2008, 2007 and 2006, we did not record any other-than-temporary impairments of Other Temporary Investments.
The following is a summary of Other Temporary Investments:

<table>
<thead>
<tr>
<th>Other Temporary Investments</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cost</td>
<td>Unrealized Gains</td>
</tr>
<tr>
<td>Cash (a)</td>
<td>$243</td>
<td>$-</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>56</td>
<td>-</td>
</tr>
<tr>
<td>Corporate Equity Securities</td>
<td>27</td>
<td>11</td>
</tr>
<tr>
<td>Total Other Temporary</td>
<td>$326</td>
<td>$11</td>
</tr>
<tr>
<td>Investments</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

Proceeds from sales of current available-for-sale securities were $1.2 billion, $10.5 billion and $17.4 billion in 2008, 2007 and 2006, respectively. Purchases of current available-for-sale securities were $1.1 billion, $10.3 billion and $17.7 billion in 2008, 2007 and 2006, respectively. During 2008, there were no gross realized gains or losses from the sale of current available-for-sale securities. Gross realized gains from the sale of current available-for-sale securities were $16 million and $39 million in 2007 and 2006, respectively. Gross realized losses from the sale of current available-for-sale securities were not material in 2007 or 2006. At December 31, 2008, the fair value of corporate equity securities with an unrealized loss position was $17 million and we had no investments in a continuous unrealized loss position for more than twelve months. At December 31, 2008, the fair value of debt securities are primarily debt based mutual funds with short-term, intermediate and long-term maturities.

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo’s accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,” allowing the receivables to be removed from the company’s balance sheet (see “Sale of Receivables – AEP Credit” section of Note 14).

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the amortization of nuclear fuel costs which are computed primarily on the units-of-production method. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs
incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator’s review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit our fuel cost calculations and deferrals. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated.

In general, changes in fuel costs in Kentucky for KPCo, Indiana (beginning July 1, 2007) and Michigan for I&M, Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia and West Virginia (beginning July 1, 2006) for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All of the profits from off-system sales are shared with customers through fuel clauses in West Virginia (beginning July 1, 2006). A portion of profits from off-system sales are shared with customers through fuel clauses in Texas, Oklahoma, Louisiana, Arkansas, Kentucky, Virginia (beginning September 1, 2007) and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions (prior to July 1, 2007 in Indiana and prior to July 1, 2006 in West Virginia), where fuel clauses were capped, frozen or suspended for a period of years, fuel costs impacted earnings.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our Consolidated Balance Sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. These power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases, including those from RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale on our Consolidated Statements of Income.
In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in our west zone where we are short capacity, we recognize as revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period before settlement. If the contract results in the physical delivery of power from a RTO or any other counterparty, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Electricity for Resale. If the contract does not result in physical delivery, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as Revenues on our Consolidated Statements of Income on a net basis (see “Derivatives and Hedging” section of Note 11).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, as well as over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge’s gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see “Cash Flow Hedging Strategies” section of Note 11).

Barging Activities

AEP River Operations’ revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer’s freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.
Construction Projects for Outside Parties

We engage in construction projects for outside parties and account for the projects on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as we incur project costs. We include such revenue and related expenses in Utility Operations revenue and Other Operation and Maintenance expense on our Consolidated Statements of Income. We also include contractually billable expenses not yet billed in Current Assets on our Consolidated Balance Sheets.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit’s refueling outage and lasting until the end of the month in which the same unit’s next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer distribution tree trimming costs for PSO and amortize the costs above the level included in base rates commensurate with recovery through a rate rider in Oklahoma.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48 beginning January 1, 2007, we classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation and Maintenance.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.
We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of certain utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series. We credit the excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries to retained earnings upon reacquisition.

**Goodwill and Intangible Assets**

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently ranging from 5 to 15 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

**Emission Allowances**

We record emission allowances at cost, including the annual SO₂ and NOₓ emission allowance entitlements received at no cost from the Federal EPA and States. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Other Noncurrent Assets – Deferred Charges and Other on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Current Assets – Prepayments and Other on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel costs and the amortization of regulatory assets for certain jurisdictions.

**Nuclear Trust Funds**

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.
We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments are considered realized losses as we do not make specific investment decisions regarding the assets held in these trusts. They reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See Note 9 for additional discussion of nuclear matters.

**Comprehensive Income (Loss)**

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

**Components of Accumulated Other Comprehensive Income (Loss) (AOCI)**

AOCI is included on our Consolidated Balance Sheets in our common shareholders’ equity section. The following table provides the components that constitute the balance sheet amount in AOCI:

<table>
<thead>
<tr>
<th>Components</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Securities Available for Sale, Net of Tax</td>
<td>$1</td>
<td>$17</td>
</tr>
<tr>
<td>Cash Flow Hedges, Net of Tax</td>
<td>(22)</td>
<td>(26)</td>
</tr>
<tr>
<td>Amortization of Pension and OPEB Deferred Costs, Net of Tax</td>
<td>12</td>
<td>-</td>
</tr>
<tr>
<td>Pension and OPEB Funded Status, Net of Tax</td>
<td>(443)</td>
<td>(145)</td>
</tr>
<tr>
<td>Total</td>
<td>$ (452)</td>
<td>$ (154)</td>
</tr>
</tbody>
</table>

**Stock-Based Compensation Plans**

At December 31, 2008, we had stock options, performance units, restricted shares and restricted stock units outstanding to employees under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in 2005.

We maintain career share accounts under the Stock Ownership Requirement Plan to facilitate executives in meeting minimum stock ownership requirements assigned to executives by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We also compensate our non-employee directors, in part, with stock units under The Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to Directors after their service ends.

In addition, we maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP stock.

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), “Share-Based Payment” (SFAS 123R), which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including stock options and employee stock purchases based on estimated fair values.

We recognize compensation expense for all share-based payment awards with service only condition granted on or after January 1, 2006 using the straight-line single-option method. In 2008, 2007 and 2006, we granted awards with performance conditions which are expensed on the accelerated multiple-option approach. Stock-based
compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2008, 2007 and 2006, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director’s stock units. See Note 15 for additional discussion.

**Earnings Per Share (EPS)**

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Consolidated Statements of Income:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in millions, except per share data)</td>
<td>$1,380</td>
<td>$1,089</td>
<td>$1,002</td>
</tr>
<tr>
<td>Earnings Applicable to Common Stock</td>
<td>$/share</td>
<td>$/share</td>
<td>$/share</td>
</tr>
<tr>
<td>Average Number of Basic Shares Outstanding</td>
<td>402.1</td>
<td>3.43</td>
<td>398.8</td>
</tr>
<tr>
<td>Average Dilutive Effect of:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Performance Share Units</td>
<td>1.2</td>
<td>0.01</td>
<td>0.9</td>
</tr>
<tr>
<td>Stock Options</td>
<td>0.1</td>
<td>-</td>
<td>0.3</td>
</tr>
<tr>
<td>Restricted Stock Units</td>
<td>0.1</td>
<td>-</td>
<td>0.1</td>
</tr>
<tr>
<td>Restricted Shares</td>
<td>0.1</td>
<td>-</td>
<td>0.1</td>
</tr>
<tr>
<td>Average Number of Diluted Shares Outstanding</td>
<td>403.6</td>
<td>$3.42</td>
<td>400.2</td>
</tr>
</tbody>
</table>

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

Options to purchase 470,016, 83,150 and 367,500 shares of common stock were outstanding at December 31, 2008, 2007 and 2006, respectively, but were not included in the computation of diluted earnings per share. Since the options’ exercise prices were greater than the year-end market price of the common shares, the effect would be antidilutive.

**Supplementary Information**

**Related Party Transactions**

For the years ended December 31, 2008, 2007 and 2006 (in millions):

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP Consolidated Revenues – Utility Operations:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned)</td>
<td>$</td>
<td>($54)</td>
<td>$</td>
</tr>
<tr>
<td>AEP Consolidated Revenues – Other:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)</td>
<td>32</td>
<td>31</td>
<td>28</td>
</tr>
<tr>
<td>AEP Consolidated Expenses – Purchased Energy for Resale:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ohio Valley Electric Corporation (43.47% Owned)</td>
<td>263</td>
<td>226</td>
<td>223</td>
</tr>
<tr>
<td>Sweeny Cogeneration Limited Partnership (a)</td>
<td>-</td>
<td>86</td>
<td>121</td>
</tr>
</tbody>
</table>

(a) In October 2007, we sold our 50% ownership in the Sweeny Cogeneration Limited Partnership. See “Sweeny Cogeneration Plant” section of Note 7.
Cash Flow Information

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest, Net of Capitalized Amounts</td>
<td>$853</td>
<td>$734</td>
<td>$664</td>
</tr>
<tr>
<td>Income Taxes, Net of Refunds</td>
<td>233</td>
<td>576</td>
<td>358</td>
</tr>
<tr>
<td>Noncash Investing and Financing Activities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acquisitions Under Capital Leases</td>
<td>62</td>
<td>160</td>
<td>106</td>
</tr>
<tr>
<td>Assumption of Liabilities Related to Acquisitions/Divestitures, Net Disposition of Assets Related to Electric Transmission Texas Joint Venture</td>
<td>-</td>
<td>8</td>
<td>-</td>
</tr>
<tr>
<td>Construction Expenditures Included in Accounts Payable at December 31,</td>
<td>460</td>
<td>345</td>
<td>404</td>
</tr>
<tr>
<td>Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,</td>
<td>38</td>
<td>84</td>
<td>-</td>
</tr>
<tr>
<td>Noncash Donation Expense Related to Issuance of Treasury Shares to AEP Foundation</td>
<td>40</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Transmission Investments

We participate in certain joint ventures which involve transmission projects to own and operate transmission facilities. These investments are recorded using the equity method and reported as Deferred Charges and Other on our Consolidated Balance Sheets.

Power Projects

During 2007, we sold our 50% interest in Sweeny, a nonregulated power plant with a capacity of 480 MW located in Texas. Our 50% interest in an international power plant totaling 600 MW located in Mexico was sold in 2006 (see “Dispositions” section of Note 7).

We account for investments in power projects that are 50% or less owned using the equity method and report them as Deferred Charges and Other on our Consolidated Balance Sheets.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. See “FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on our previously reported net income or changes in shareholders’ equity.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that we have determined relate to our operations.

Pronouncements Adopted in 2008

The following standards were effective during 2008. Consequently, the financial statements and footnotes reflect their impact.

SFAS 157 “Fair Value Measurements” (SFAS 157)

We partially adopted SFAS 157 effective January 1, 2008. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures.
In February 2008, the FASB issued FSP SFAS 157-1 “Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13” (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 “Accounting for Leases” (SFAS 13) and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. SFAS 157-1 was effective upon issuance and had an immaterial impact on our financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 “Effective Date of FASB Statement No. 157” (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had an immaterial impact on our financial statements.

In October 2008, the FASB issued FSP SFAS 157-3 “Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active” which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on our financial statements.

See “SFAS 157 Fair Value Measurements” Section of Note 11 for further information.

**SFAS 159 “The Fair Value Option for Financial Assets and Financial Liabilities” (SFAS 159)**

The FASB permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

We adopted SFAS 159 effective January 1, 2008. At adoption, we did not elect the fair value option for any assets or liabilities.

**SFAS 162 “The Hierarchy of Generally Accepted Accounting Principles” (SFAS 162)**

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

We adopted SFAS 162 in the fourth quarter of 2008. The adoption of this standard had no impact on our financial statements.

**EITF Issue No. 06-10 “Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements” (EITF 06-10)**

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.
EITF Issue No. 06-11 “Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards” (EITF 06-11)

In June 2007, the FASB addressed the recognition of income tax benefits of dividends on employee share-based compensation. Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

We adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on our financial statements.

FSP SFAS 133-1 and FIN 45-4 “Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161” (FSP SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued FSP SFAS 133-1 and FIN 45-4 amending SFAS 133 and FIN 45 “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.” Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

We adopted the standard effective December 31, 2008. The adoption of this standard had no impact on our financial statements but increased our guarantees disclosures in Note 6.

FSP SFAS 140-4 and FIN 46R-8 “Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities” (FSP SFAS 140-4 and FIN 46R-8)

In December 2008, the FASB issued FSP SFAS 140-4 and FIN 46R-8 amending SFAS 140 “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities” and FIN 46R “Consolidation of Variable Interest Entities.” Under the requirements, the transferor of financial assets in the securitization or asset-backed financing arrangement must disclose the following:

(a) Nature of any restrictions on assets reported by an entity in its balance sheet that relate to a transferred financial asset, including the carrying amounts of such assets.
(b) Method of reporting servicing assets and servicing liabilities.
(c) If reported as sales and the transferor has continuing involvement with the transferred financial assets and the transfers are accounted for as secured borrowings, how the transfer of financial assets affects the transferors’ balance sheet, net income and cash flows.
The FIN 46R amendments contain disclosure requirements for a public enterprise that (a) is the primary beneficiary of a variable interest entity (VIE), (b) holds a significant variable interest in a VIE but is not the primary beneficiary or (c) is a sponsor that holds a variable interest in a VIE. The principle objectives of the disclosures required by this standard are to provide financial statement users an understanding of:

(a) Significant judgments and assumptions made to determine whether to consolidate a variable interest entity and/or disclose information about involvement with a variable interest entity.
(b) Nature of the restrictions on a consolidated variable interest entity’s assets reported in the balance sheet, including the carrying amounts of such assets.
(c) Nature of, and changes in, risks associated with a company’s involvement with a variable interest entity.
(d) A variable interest entity’s effect on the balance sheet, net income and cash flows.
(e) The nature, purpose, size and activities of any variable interest equity, including how it is financed.

We adopted the standard effective December 31, 2008. The adoption of this standard had no impact on our financial statements but increased our footnote disclosures for variable interest entities. See “Principles of Consolidation” section of Note 1.

**FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” (FSP FIN 39-1)**

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 39 “Offsetting of Amounts Related to Certain Contracts” by replacing the interpretation’s definition of contracts with the definition of derivative instruments per SFAS 133. The amendment requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

We adopted the standard effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, we reclassified the following amounts on the December 31, 2007 Consolidated Balance Sheet as shown:

<table>
<thead>
<tr>
<th>Balance Sheet Line Description</th>
<th>As Reported for the December 2007 10-K</th>
<th>FSP FIN 39-1 Reclassification (in millions)</th>
<th>As Reported for the December 2008 10-K</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>$286</td>
<td>($15)</td>
<td>$271</td>
</tr>
<tr>
<td>Margin Deposits</td>
<td>58</td>
<td>(11)</td>
<td>47</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>340</td>
<td>(21)</td>
<td>319</td>
</tr>
<tr>
<td>Current Liabilities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>250</td>
<td>(10)</td>
<td>240</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>337</td>
<td>(36)</td>
<td>301</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>189</td>
<td>(1)</td>
<td>188</td>
</tr>
</tbody>
</table>

For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2008 balance sheet, we netted $11 million of cash collateral received from third parties against short-term and long-term risk management assets and $43 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

**Pronouncements Adopted During The First Quarter of 2009**

The following standards are effective during the first quarter of 2009. Consequently, their impact will be reflected in the first quarter of 2009 financial statements when filed. The following paragraphs discuss their expected impact on future financial statement and footnote disclosures.
SFAS 141 (revised 2007) “Business Combinations” (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments.

We adopted SFAS 141R effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. We will apply it to any future business combinations.

SFAS 160 “Noncontrolling Interest in Consolidated Financial Statements” (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

We adopted SFAS 160 effective January 1, 2009. The adoption of this standard had an immaterial impact and will be applied retrospectively to prior period financial statements in future filings so the presentation of noncontrolling interest is comparable.

SFAS 161 “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation.

We adopted SFAS 161 effective January 1, 2009. This standard will increase our disclosure requirements related to derivative instruments and hedging activities in future reports.

EITF Issue No. 08-5 “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer’s credit standing without the support of the credit enhancement affect the fair value measurement of the issuer’s liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

We adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as we report fair value of long-term debt annually.
EITF Issue No. 08-6 “Equity Method Investment Accounting Considerations” (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

We adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements. It was applied prospectively.

FSP EITF 03-6-1 “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities” (EITF 03-6-1)

In June 2008, the FASB addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method described in SFAS 128 “Earnings per Share.”

We adopted EITF 03-6-1 effective January 1, 2009. The adoption of this standard had an immaterial impact on our financial statements.

FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets” (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

We adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 132R-1 “Employers’ Disclosures about Postretirement Benefit Plan Assets” (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, earnings per share calculations, leases, insurance, hedge accounting consolidation policy, trading inventory and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.
**EXTRAORDINARY ITEM**

**Virginia Restructuring**

In April 2007, Virginia passed legislation to reestablish regulation for retail generation and supply of electricity. As a result, we recorded an extraordinary loss of $118 million ($79 million, net of tax) in 2007 for the reestablishment of regulatory assets and liabilities related to our Virginia retail generation and supply operations. In 2000, we discontinued SFAS 71 regulatory accounting in our Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation.

### 3. GOODWILL AND OTHER INTANGIBLE ASSETS

#### Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2008 and 2007 by operating segment are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Utility Operations</th>
<th>AEP River Operations</th>
<th>AEP Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td><strong>Balance at December 31, 2006</strong></td>
<td>$ 37</td>
<td>$ 39</td>
<td>$ 76</td>
</tr>
<tr>
<td>Impairment Losses</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2007</strong></td>
<td>37</td>
<td>39</td>
<td>76</td>
</tr>
<tr>
<td>Impairment Losses</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2008</strong></td>
<td>$ 37</td>
<td>$ 39</td>
<td>$ 76</td>
</tr>
</tbody>
</table>

In the fourth quarters of 2008 and 2007, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses.

#### Other Intangible Assets

Acquired intangible assets subject to amortization were $12.8 million and $15.2 million at December 31, 2008 and 2007, respectively, net of accumulated amortization and are included in Deferred Charges and Other on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

<table>
<thead>
<tr>
<th>Amortization Life</th>
<th>Gross Carrying Amount</th>
<th>Accumulated Amortization</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in years)</td>
<td>(in millions)</td>
<td>(in millions)</td>
</tr>
<tr>
<td>Patent</td>
<td>5</td>
<td>$ -</td>
</tr>
<tr>
<td>Easements</td>
<td>10</td>
<td>2.2</td>
</tr>
<tr>
<td>Purchased Technology</td>
<td>10</td>
<td>10.9</td>
</tr>
<tr>
<td>Advanced Royalties</td>
<td>15</td>
<td>29.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 42.5</td>
<td>$ 29.7</td>
</tr>
</tbody>
</table>

Amortization of intangible assets was $3 million, $4 million and $5 million for 2008, 2007 and 2006, respectively. Our estimated total amortization is $3 million per year for 2009 through 2010, $2 million for 2011 and $1 million per year for 2012 through 2016, when all assets will be fully amortized with no residual value.

The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. In December 2008, we received an order from the LPSC that extended the useful life of the mine for an additional five years, beginning January 1, 2008, which is included in the table above and factored in the estimates noted above for future periods.

Other than goodwill, we have no intangible assets that are not subject to amortization.
4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on net income and cash flows.

For discussion of the FERC’s November 2008 order on AEP’s allocation of off-system sales, see “Allocation of Off-system Sales Margins” section within “FERC Rate Matters”.

Ohio Rate Matters

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amended the restructuring law effective July 31, 2008 and required electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities could include a fuel cost recovery mechanism (FCR) in their ESP filing. Electric utilities also had an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, would have transitioned CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve and/or modify each utility’s ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than an MRO. Both alternatives involve a “significantly excessive earnings” test (SEET) based on what public companies, including other utilities with similar risk profiles, earn on equity.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo’s and OPCo’s ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a FCR that primarily includes fuel costs, purchased power costs, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The FCR is proposed to be phased into customer bills over the three-year period from 2009 through 2011 and recovered with a weighted average cost of capital carrying cost deferral over seven years from 2012 through 2018. If the ESPs are approved as filed, effective with the implementation of the ESPs, CSPCo and OPCo will defer fuel cost over/under-recoveries and related carrying costs, including amounts unrecovered through the phase in period, for future recovery.

In addition to the FCR, the requested ESP increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include recovery for programs for smart metering initiatives, economic development, mandated energy efficiency, renewable resources and peak demand reduction programs.

Within the ESP requests, CSPCo and OPCo would also recover existing regulatory assets of $47 million and $39 million, respectively, for customer choice implementation and line extension carrying costs incurred through December 2008. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $31 million and $23 million, respectively, through December 2008. The PUCO had previously issued orders allowing deferral of these costs. Such costs would be recovered over an 8-year period beginning January 2011. If the PUCO does not approve recovery of these regulatory assets in this or some future proceeding, it would have an adverse effect on future net income and cash flows.

Hearings were held in November and December 2008. Many intervenors filed opposing testimony. CSPCo and OPCo requested retroactive application of the new rates, including the FCR, back to the start of the January 2009 billing cycle upon approval of the ESPs. The RSP rates were effective for the years ended December 31, 2006, 2007 and 2008 under which CSPCo and OPCo had three annual generation rate increases of 3% and 7%, respectively. The RSP also allowed additional annual generation rate increases of up to an average of 4% per year to recover new governmentally-mandated costs. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. A motion to dismiss the application has been filed by Ohio Partners for Affordable Energy, while the Ohio Consumers’ Counsel has filed comments opposing the application. The PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO
issues a ruling on the ESPs or the end of the March 2009 billing cycle, whichever comes first. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs. CSPCo and OPCo anticipate a final order from the PUCO during the first quarter of 2009.

### 2008 Generation Rider and Transmission Rider Rate Settlement

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider (TCRR) provisions of the RSP. The increase was due to additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of increased PJM costs associated with transmission line losses of $39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets during the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings previously expensed from June 2007 to December 2007 for transmission line losses. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR recoveries are under/over actual net costs, CSPCo and OPCo will defer the difference as a regulatory asset or regulatory liability and adjust future customer billings to reflect actual costs, including carrying costs on the deferral. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008. The TCRR continues in CSPCo’s and OPCo’s proposed ESPs to provide for the recovery of PJM related costs.

### 2009 Generation Rider and Transmission Rider

In October 2008, CSPCo and OPCo filed an application to update the TCRR. The application requested an average decrease of 3% for CSPCo and an average increase of 7% for OPCo, including under recoveries from the prior year and related carrying charges. Based on the requests, CSPCo’s annual revenues would decrease approximately $5 million and OPCo’s annual revenues would increase approximately $13 million.

In December 2008, the PUCO issued a final order approving the application with certain modifications. First, the rate to calculate carrying costs will change from using a current weighted average cost of capital rate (WACC), which includes a return on equity and a gross up for income taxes, to a long-term debt rate. CSPCo’s and OPCo’s approved long-term debt rates were 5.73% and 5.71%, respectively. In addition, the TCRR application eliminated the fuel-related credit which had been applied against the PJM transmission marginal line loss since CSPCo’s and OPCo’s proposed fuel adjustment clause in the filing of the ESP includes this credit. The new TCRR became effective with the January 2009 billing cycle.

### Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the generation rates which may be a market-based standard service offer price for generation and the expected higher cost of operating and maintaining the plant, including a return on and return of the projected cost to construct the plant.

In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected $12 million in pre-construction costs and incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million.

The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In 2006, intervenors filed four separate appeals of the PUCO’s order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO’s order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing
law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to
the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery
and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved
orders of the PUCO. In September 2008, the Ohio Consumers’ Counsel filed a motion with the PUCO requesting
all Phase 1 costs be refunded to Ohio ratepayers with interest because the Ohio Supreme Court invalidated the
underlying foundation for the Phase 1 recovery. In October 2008, CSPCo and OPCo filed a motion with the PUCO
that argued the Ohio Consumers’ Counsel’s motion was without legal merit and contrary to past precedent.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement
outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a
continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that
CSPCo and OPCo have not commenced construction of the IGCC plant and believe there exist real statutory barriers
to the construction of any new base load generation in Ohio, including IGCC plants. The statement also indicated
that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in
the commencement of construction on a continuous course by that time.

As of December 2007 the estimate cost to build the IGCC plant was $2.7 billion which has continued to increase
significantly. Management continues to pursue the ultimate construction of the IGCC plant. However, CSPCo and
OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists.

If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in
another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future
net income and cash flows. Management cannot predict the outcome of the cost recovery litigation concerning the
Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

**Ormet**

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW
load, in accordance with a settlement agreement approved by the PUCO. The settlement agreement allows for the
recovery in 2007 and 2008 of the difference between the $43 per MWH Ormet pays for power and a PUCO
approved market price, if higher. The PUCO approved a $47.69 per MWH market price for 2007 and the difference
was recovered through the amortization of an existing $57 million ($15 million for CSPCo and $42 million for
OPCo) regulatory liability related to excess deferred state taxes resulting from the phase-out of an Ohio franchise tax
recorded in 2005. During 2007, CSPCo and OPCo each amortized $7 million of this regulatory liability to increase
income. During 2008, CSPCo and OPCo each amortized $21.5 million of this regulatory liability to income based
on PUCO approved market prices. The settlement agreement required CSPCo and OPCo to exhaust the $57 million
regulatory liability. Therefore, CSPCo reimbursed OPCo for $13.5 million of OPCo’s unamortized regulatory
liability. The previously approved 2007 price of $47.69 per MWH was used through November 2008 when the
PUCO approved a 2008 price of $53.03 per MWH. The additional amortization recorded in December 2008 of $11
million each for CSPCo and OPCo related to the increase in the 2008 PUCO approved market price for the period
January 2008 through November 2008. As of December 31, 2008, the regulatory liability was fully amortized.

In December 2008, CSPCo, OPCo and Ormet filed an application with the PUCO for approval of an interim
arrangement governing the provision of generation service to Ormet. The arrangement would remain in effect and
expire upon the effective date of CSPCo’s and OPCo’s new ESP rates and the effective date of a new arrangement
between Ormet and CSPCo/OPCo approved by the PUCO. Under the interim arrangement, Ormet would pay the
applicable generation tariff rates and riders. CSPCo and OPCo sought to defer as a regulatory asset beginning in
2009 the difference between the PUCO approved 2008 market price and the applicable generation tariff rates and
riders. CSPCo and OPCo propose to recover the deferral through the fuel adjustment clause mechanism they
proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement.
Although the PUCO did not address recovery in this order, it is expected to be resolved in the pending ESP
proceedings. In February 2009, an intervenor filed an application for rehearing of the PUCO’s interim arrangement
approval. In February 2009, Ormet filed an application with the PUCO for approval of a proposed power contract
for 2009 through 2018. Ormet proposed that it pay varying amounts based on certain conditions, including the price
of aluminum. The difference between the amounts paid by Ormet and the otherwise applicable PUCO tariff rate
would be either collected from or refunded to CSPCo’s and OPCo’s retail customers.
Hurricane Ike

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. Under the RSP, CSPCo and OPCo could seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively. In December 2008, CSPCo and OPCo filed with the PUCO a request to establish the regulatory assets, plus carrying costs using CSPCo’s and OPCo’s weighted average cost of capital carrying charge rates. In December 2008, the PUCO subsequently approved the establishment of the regulatory assets but authorized CSPCo and OPCo to record a long-term debt only carrying cost on the regulatory asset. In its order approving the deferrals, the PUCO stated that recovery would be determined in CSPCo’s and OPCo’s future filings.

In December 2008, the Consumers for Reliable Electricity in Ohio filed a request with the PUCO asking for an investigation into the service reliability of Ohio’s investor-owned electric utilities, including CSPCo and OPCo. The investigation request includes the widespread outages caused by the September 2008 wind storm. CSPCo and OPCo filed a response asking the PUCO to deny the request.

As a result of the past favorable treatment of storm restoration costs and the RSP provisions, which were in effect when the storm occurred and the filings made, management believes the recovery of the regulatory assets is probable. However, if these regulatory assets are not recovered, it would have an adverse effect on future net income and cash flows.

Texas Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 million, respectively. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. The significant items appealed by TCC were:

- The PUCT ruling that TCC did not comply with the Texas Restructuring Legislation and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues.
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because TCC failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and TCC bundled out-of-the-money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC’s net stranded generation plant costs.
- Two federal matters regarding the allocation of off-system sales related to fuel recoveries and a potential tax normalization violation.

Municipal customers and other intervenors also appealed the PUCT true-up orders seeking to further reduce TCC’s true-up recoveries.

In March 2007, the Texas District Court judge hearing the appeals of the true-up order affirmed the PUCT’s April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs and remanded this matter to the PUCT for further consideration. The District Court judge also determined that the PUCT improperly reduced TCC’s net stranded plant costs for commercial unreasonableness.
TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but two major respects. It reversed the District Court’s unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the “excess earnings” that had already been refunded to affiliated retail electric providers. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earning based upon the reasons discussed in the “TCC Excess Earnings” section below. The favorable commercial unreasonableness judgment entered by the District Court was not reversed. The Texas Court of Appeals denied intervenors’ motion for rehearing. In May 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not determined if it will grant review.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. Appeals brought by intervenors and TNC of the final true-up order remain pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future net income, cash flows and financial condition.

**TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes**

Appeals remain outstanding related to the stranded costs true-up and related orders regarding whether the PUCT may require TCC to refund certain tax benefits to customers. The PUCT reduced TCC’s securitized stranded costs by certain tax benefits. Subsequent to the reduction, the PUCT allowed TCC to defer $103 million of ordered CTC refunds for other true-up items to negate the securitization reduction. Of the $103 million, $61 million relates to the present value of certain tax benefits applied to reduce the securitization stranded generating assets and $42 million relates to carrying costs. The deferral of the CTC refunds is pending resolution on whether the PUCT’s securitization refund is an IRS normalization violation.

Evidence includes a March 2008 IRS issuance of final regulations addressing the normalization requirements for the treatment of Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) in a stranded cost determination. Consistent with a Private Letter Ruling TCC received in 2006, the regulations clearly state that TCC will sustain a normalization violation if the PUCT orders TCC to flow the tax benefits to customers as part of the stranded cost true-up. TCC notified the PUCT that the final regulations were issued and the PUCT made its request to the court. In May 2008, as requested by the PUCT, the Texas Court of Appeals ordered a remand of the tax normalization issue for the consideration of this additional evidence.

TCC expects that the PUCT will allow TCC to retain these amounts. This will have a favorable effect on future net income and cash flows as TCC will be free to amortize the deferred ADITC and EDFIT tax benefits due to the sale of the generating plants that generated the tax benefits. Since management expects that the PUCT will allow TCC to retain the deferred CTC refund amounts in order to avoid an IRS normalization violation, management has not accrued any related interest expense for refunds of these amounts. If accrued, management estimates interest expense would have been approximately $4 million higher for the period July 2008 through December 2008 based on a CTC interest rate of 7.5%.

If the PUCT orders TCC to return the tax benefits to customers, thereby causing TCC to violate the IRS’ normalization regulations, it could result in TCC’s repayment to the IRS, under the normalization rules, of ADITC on all property, including transmission and distribution property. This amount approximates $103 million as of December 31, 2008. It could also lead to a loss of TCC’s right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay to the IRS its ADITC and is also required to refund ADITC to customers, it would have an unfavorable effect on future net income and cash flows. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are actually returned to ratepayers under a nonappealable order. Management intends to continue to work with the PUCT to favorably resolve the issue and avoid the adverse effects of a normalization violation on future net income, cash flows and financial condition.
**TCC Excess Earnings**

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded cost recoveries from REPs in the True-up Proceeding. It is possible that TCC’s stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy.

In May 2008, the Texas Court of Appeals issued a decision in TCC’s True-up Proceeding determining that even though excess earnings had been previously refunded to REPs, TCC still must reduce stranded cost recoveries in its True-up Proceeding. In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset of $55 million representing a receivable from the REPs for prior excess earnings refunds made to them by TCC. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund additional amounts of excess earnings or interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would have an adverse effect on future net income and cash flows. AEP sold its affiliate REPs in December 2002. While AEP owned the affiliate REPs, TCC refunded $11 million of excess earnings to the affiliate REPs. Management cannot predict the outcome of the excess earnings remand and whether it would have an adverse effect on future net income and cash flows.

**OTHER TEXAS RATE MATTERS**

**Hurricanes Dolly and Ike**

In July and September 2008, TCC’s service territory in south Texas was hit by Hurricanes Dolly and Ike, respectively. TCC incurred $23 million and $2 million in incremental maintenance costs related to service restoration efforts for Hurricanes Dolly and Ike, respectively. TCC has a PUCT approved catastrophe reserve which permits TCC to collect $1.3 million on an annual basis with authority to continue the collection until the catastrophe reserve reaches $13 million. Any incremental storm-related maintenance costs can be charged against the catastrophe reserve if the total incremental maintenance costs for a storm exceed $500 thousand. In June 2008, prior to these hurricanes, TCC had approximately $2 million recorded in the catastrophe reserve account. Therefore, TCC established a net regulatory asset for $23 million.

Under Texas law and as previously approved by the PUCT in prior base rate cases, the regulatory asset will be included in rate base in the next base rate filing. At that time, TCC will evaluate the existing catastrophe reserve amounts and review potential future events to determine the appropriate funding level to request to both recover the regulatory asset and fund a reserve for future storms.

**ETT**

In December 2007, TCC contributed $70 million of transmission facilities to ETT, an AEP joint venture accounted for using the equity method. The PUCT approved ETT's initial rates, its request for a transfer of facilities and a certificate of convenience and necessity to operate as a stand alone transmission utility in the ERCOT region. ETT was allowed a 9.96% after tax return on equity rate in those approvals. In 2008, intervenors filed a notice of appeal to the Travis County District Court. In October 2008, the court ruled that the PUCT exceeded its authority by approving ETT’s application as a stand alone transmission utility without a service area under the wrong section of the statute. Management believes that ruling is incorrect. Moreover, ETT provided evidence in its application that ETT complied with what the court determined was the proper section of the statute. In January 2009, ETT and the PUCT filed appeals to the Texas Court of Appeals. As of December 31, 2008, AEP’s net investment in ETT was $15 million. In January 2009, TCC sold $60 million of transmission facilities to ETT. See “Electric Transmission Texas LLC (ETT)” section of Note 7. Depending upon the ultimate outcome of the appeals and any resulting remands, TCC may be required to reacquire transferred assets and projects under construction by ETT.
ETT, TCC and TNC are involved in transactions relating to the transfer to ETT of other transmission assets, which are in various stages of review and approval. In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the Competitive Renewable Energy Zone (CREZ) initiative. The CREZ initiative is the development of 2,400 miles of new transmission lines to transport electricity from 18,000 megawatts of planned wind farm capacity in west Texas to rapidly growing cities in eastern Texas. In January 2009, the PUCT announced its decision to authorize ETT to construct CREZ related projects. ETT has estimated that the PUCT’s decision authorizes ETT to construct $750 million to $850 million of new transmission assets.

**Stall Unit**

See “Stall Unit” section within “Louisiana Rate Matters” for disclosure.

**Turk Plant**

See “Turk Plant” section within “Arkansas Rate Matters” for disclosure.

**Virginia Rate Matters**

**Virginia Base Rate Filing**

In May 2008, APCo filed an application with the Virginia SCC to increase its base rates by $208 million on an annual basis. The proposed revenue requirement reflected a return on equity of 11.75%. As permitted under Virginia law, APCo implemented these new base rates, subject to refund, effective October 28, 2008.

In October 2008, APCo submitted a $168 million settlement agreement to the Virginia SCC which was accepted by most parties. The $168 million settlement agreement revenue requirement was determined using a 10.2% return on equity and reflected the Virginia SCC staff’s recommended increase as adjusted.

In November 2008, the Virginia SCC issued a final order approving the settlement agreement which increased APCo’s annual base revenues by $168 million. The new authorized rates were implemented in December 2008, retroactive to October 28, 2008. APCo made customer refunds with interest in January 2009 for the difference between the interim rates and the approved rates.

**Virginia E&R Costs Recovery Filing**

In May 2008, APCo filed a request with the Virginia SCC to recover $66 million of its incremental E&R costs incurred for the period of October 2006 to December 2007. In September 2008, a settlement was reached and a stipulation agreement (stipulation) to recover $61 million of costs was submitted to the hearing examiner. In October 2008, the Virginia SCC approved the stipulation which will have a favorable effect on 2009 cash flows of $61 million and on net income for the previously unrecognized equity carrying costs of approximately $11 million.

As of December 31, 2008, APCo has $123 million of deferred Virginia incremental E&R costs (excluding $25 million of unrecognized equity carrying costs). The $123 million consists of $6 million of over recovery of costs collected from the 2008 surcharge, $50 million approved by the Virginia SCC related to APCo’s May 2008 E&R filing to be recovered in 2009, and $79 million, representing costs deferred in 2008, to be included in the 2009 E&R filing, to be collected in 2010.

If the Virginia SCC were to disallow a material portion of APCo’s 2008 deferral of incremental E&R costs, it would have an adverse effect on future net income and cash flows.

**Virginia Fuel Clause Filing**

In July 2008, APCo initiated a fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily related to increases in coal costs. In October 2008, the Virginia SCC ordered an annualized increase of $117 million based on differences in estimated future costs and inclusive of PJM transmission marginal line losses, subject to subsequent true-up to actual.
APCo’s Filings for an IGCC Plant

In January 2006, APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC plant adjacent to APCo’s existing Mountaineer Generating Station in Mason County, West Virginia.

In June 2007, APCo sought pre-approval with the WVPSC for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing finance costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo’s requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action.

Through December 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to the West Virginia jurisdiction, approximately $2 million applicable to the FERC jurisdiction and approximately $9 million allocated to the Virginia jurisdiction.

In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expense being incurred and certification of the IGCC plant prior to July 2010.

Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

Mountaineer Carbon Capture Project

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO2 capture demonstration facility. APCo and Alstom will each own part of the CO2 capture facility. APCo will also construct and own the necessary facilities to store the CO2. RWE AG, a German electric power and natural gas public utility, is participating in the evaluation of the commercial and technical feasibility of taking captured CO2 from the flue gas stream and storing it in deep geologic formations. APCo’s estimated cost for its share of the facilities is $76 million. Through December 31, 2008, APCo incurred $29 million in capitalized project costs which are included in Regulatory Assets. APCo is earning a return on the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. See the “Virginia Base Rate Filing” section above. APCo plans to seek recovery for the CO2 capture and storage project costs in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. If a significant portion of the deferred project costs are excluded from base rates and ultimately disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.
West Virginia Rate Matters

APCo’s and WPCo’s 2008 Expanded Net Energy Cost (ENEC) Filing

In February 2008, APCo and WPCo filed with the WVPSC for an increase of approximately $156 million including a $135 million increase in the ENEC, a $17 million increase in construction cost surcharges and $4 million of reliability expenditures, to become effective July 2008. In June 2008, the WVPSC issued an order approving a joint stipulation and settlement agreement granting rate increases, effective July 2008, of approximately $106 million based on differences in estimated future costs, including an $88 million increase in the ENEC, a $14 million increase in construction cost surcharges and $4 million of reliability expenditures. The ENEC is an expanded form of a fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits, PJM costs associated with transmission line losses due to the implementation by PJM transmission marginal line loss pricing and other energy/transmission items.

The ENEC and reliability surcharges are subject to a true-up to actual costs. Therefore, there should be no earnings effect if actual costs exceed the recoveries due to the deferral of any under-recovery of costs. The construction cost is not subject to a true-up to actual costs and could impact future net income and cash flows if actual costs exceed the amounts approved for recovery.

APCo’s Filings for an IGCC Plant

See “APCo’s Filings for an IGCC Plant” section within “Virginia Rate Matters” for disclosure.

Mountaineer Carbon Capture Project

See “Mountaineer Carbon Capture Project” section within “Virginia Rate Matters” for disclosure.

Indiana Rate Matters

Indiana Base Rate Filing

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The filing also requested trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of PJM transmission marginal line loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers would initially increase annual revenues by an additional $45 million. I&M proposes to share with customers, through a proposed tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement included a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue. The agreement also establishes an off-system sales sharing mechanism and trackers for PJM, net emission allowance, and DSM costs, among other provisions which include continued funding for the eventual decommissioning of the Cook Nuclear Plant. I&M anticipates a final order from the IURC during the first quarter of 2009.

Rockport and Tanners Creek

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NOx and mercury from existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport plant. I&M is requesting to depreciate the ACI systems over a period of 10 years and the SNCR systems over the remaining useful life of the Tanners Creek generating units. I&M requested
the IURC to approve a rate adjustment mechanism of unrecovered carrying costs during construction and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the projects are placed in service. I&M also requested the IURC to authorize deferral of costs and carrying costs until such costs are recognized in the rate adjustment mechanism. The IURC has not issued a procedural schedule at this time for this petition. Management is unable to predict the outcome of this petition.

**Indiana Fuel Clause Filing**

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of the extended outage of the Cook Unit 1 due to damage to the main turbine and generator and increased coal prices, and a projection for the future period of fuel costs including Cook Unit 1 replacement power fuel clause costs. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Unit 1 accidental outage policy. See “Cook Plant Unit 1 Fire and Shutdown” section within the “Commitment, Guarantees and Contingencies” footnote for further details. I&M reached an agreement in February 2009 with intervenors to collect the under-recovery over twelve months instead of over six months as proposed. Under the agreement, the fuel factor will go into effect subject to refund and a subdocket will be established to consider issues relating to the Cook Unit 1 outage and I&M’s fuel procurement practices. A decision from the IURC is still pending.

**Michigan Rate Matters**

**Michigan Restructuring**

Although customer choice commenced for I&M’s Michigan customers on January 1, 2002, I&M’s rates for generation in Michigan continued to be cost-based regulated because none of I&M's customers elected to change suppliers and no alternative electric suppliers were registered to compete in I&M's Michigan service territory. In October 2008, the Governor of Michigan signed legislation to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year and to require the remaining 90% of annual retail load to be phased into cost-based rates. The new legislation also requires utilities to meet certain energy efficiency and renewable portfolio standards and permits cost recovery of meeting those standards. Management continues to conclude that I&M's rates for generation in Michigan are cost-based regulated and that I&M can practice regulatory accounting.

**Kentucky Rate Matters**

**2008 Fuel Cost Reconciliation**

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM’s implementation of PJM transmission marginal line loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo’s semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the year ended December 31, 2008, KPCo recorded $20 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through December 2008 of which $7 million related to 2007.

**Oklahoma Rate Matters**

**PSO Fuel and Purchased Power**

**2006 and Prior Fuel and Purchased Power**

Proceedings addressing PSO’s historic fuel costs through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement. For further discussion and estimated effect on net income see “Allocation of Off-system Sales Margins” section within “FERC Rate Matters”.

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In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that allowed PSO to retain the $42 million from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending.

2007 Fuel and Purchased Power

In September 2008, the OCC initiated a review of PSO’s generation, purchased power and fuel procurement processes and costs for 2007. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

Red Rock Generating Facility

In July 2006, PSO announced an agreement with Oklahoma Gas and Electric Company (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit. PSO would have owned 50% of the new unit. OG&E and PSO requested pre-approval to construct the coal-fired Red Rock Generating Facility (Red Rock) and to implement a recovery rider.

In October 2007, the OCC issued a final order approving PSO’s need for 450 MWs of additional capacity by the year 2012, but rejected the ALJ’s recommendation and denied PSO’s and OG&E’s applications for construction pre-approval. The OCC stated that PSO failed to fully study other alternatives to a coal-fired plant. Since PSO and OG&E could not obtain pre-approval to build Red Rock, PSO and OG&E cancelled the third party construction contract and their joint venture development contract.

In December 2007, PSO filed an application at the OCC requesting recovery of $21 million in pre-construction costs and contract cancellation fees associated with Red Rock. In March 2008, PSO and all other parties in this docket signed a settlement agreement that provided for recovery of $11 million of Red Rock pre-construction costs and carrying costs at PSO’s AFUDC rate beginning in March 2008 and continuing until the $11 million is included in base rates in PSO’s next base rate case. PSO will recover the costs over the expected life of the peaking facilities at the Southwestern Station, and include the costs in rate base in its next base rate filing. The OCC approved the settlement in May 2008. As a result of the settlement, PSO wrote off $10 million of its deferred pre-construction costs/cancellation fees in the first quarter of 2008. The remaining balance of $11 million was recorded as a regulatory asset. In July 2008, PSO filed a base rate case which included $11 million of deferred Red Rock costs plus carrying charges at PSO’s AFUDC rate beginning in March 2008. In January 2009, the OCC approved the base rate case. See “2008 Oklahoma Base Rate Filing” section below.

Oklahoma 2007 Ice Storms

In January and December 2007, PSO incurred maintenance expenses for two large ice storms. Prior to December 2007, PSO filed with the OCC requesting recovery of the maintenance expenses related to the January 2007 service restoration efforts. PSO proposed in its application to establish a regulatory asset to defer the previously expensed ice storm restoration costs and to offset the regulatory asset with gains from the sale of excess SO2 emission allowances.

In February 2008, PSO entered into a settlement agreement for recovery of ice storm restoration costs from both ice storms. In March 2008, the OCC approved the settlement agreement subject to a final audit. Therefore, in March 2008, PSO recorded a regulatory asset for the previously expensed ice storm maintenance costs. In October 2008, PSO received final approval to recover $74 million of ice storm costs. PSO has applied and will continue to apply proceeds from sale of excess SO2 emission allowances to reduce the regulatory asset. The estimated net balance that is not recovered from the sale of emission allowances will be amortized and recovered through a rider over a period of five years which began in November 2008. The rider will ultimately be trued-up to recover the entire $74 million regulatory asset. The regulatory asset earns a return of 10.92% until fully recovered.
2008 Oklahoma Base Rate Filing

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million (later adjusted to $127 million) on an annual basis. PSO has been recovering costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO’s net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO’s non-fuel base revenues and a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO’s program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. This deferral will be recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009.

In January 2009, PSO and one intervenor filed motions with the OCC to modify its final order. PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment the OCC made on prepaid pension funding contained within the OCC final order. The OCC subsequently declined to consider the motions to modify. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several issues. If the Attorney General and/or the intervenor’s Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

Louisiana Rate Matters

Louisiana Compliance Filing

In connection with SWEPCo’s merger related compliance filings, the LPSC approved a settlement agreement in April 2008 that prospectively resolves all issues regarding claims that SWEPCo had over-earned its allowed return. SWEPCo agreed to a formula rate plan (FRP) with a three-year term. Under the plan, beginning in August 2008, rates shall be established to allow SWEPCo to earn an adjusted return on common equity of 10.565%. The adjustments are standard Louisiana rate filing adjustments.

If in the second and third year of the FRP, the adjusted earned return is within the range of 10.015% to 11.115%, no adjustment to rates is necessary. However, if the adjusted earned return is outside of the above-specified range, an FRP rider will be established to increase or decrease rates prospectively. If the adjusted earned return is less than 10.015%, SWEPCo will prospectively increase rates to collect 60% of the difference between 10.565% and the adjusted earned return. Alternatively, if the adjusted earned return is more than 11.115%, SWEPCo will prospectively decrease rates by 60% of the difference between the adjusted earned return and 10.565%. SWEPCo will not record over/under recovery deferrals for refund or future recovery under this FRP.

The settlement provides for a separate credit rider decreasing Louisiana retail base rates by $5 million prospectively over the entire three-year term of the FRP, which shall not affect the adjusted earned return in the FRP calculation. This separate credit rider will cease effective August 2011.

In addition, the settlement provides for a reduction in generation depreciation rates effective October 2007. SWEPCo deferred as a regulatory liability the effects of the expected depreciation reduction through July 2008. SWEPCo will amortize this regulatory liability over the three-year term of the FRP as a reduction to the cost of service used to determine the adjusted earned return.

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In accordance with the settlement, SWEPCo recorded a $4 million regulatory liability related to the reduction in generation depreciation rates. The amount of the unamortized regulatory liability for the reduction in generation depreciation was $3 million as of December 31,
In August 2008, the LPSC approved the settlement and SWEPCo implemented the FRP rates, subject to refund. No provision for refund has been recorded as SWEPCo believes that the rates as implemented are in compliance with the settlement.

**Stall Unit**

In May 2006, SWEPCo announced plans to build a new intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit (the Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $384 million, excluding AFUDC, and is expected to be in-service in mid-2010. The Louisiana Department of Environmental Quality issued an air permit for the Stall unit in March 2008.

In March 2007, the PUCT approved SWEPCo’s request for a certificate for the facility based on a prior cost estimate. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million (excluding transmission). In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC has established a procedural schedule with a public hearing for April 2009.

If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized construction costs including any cancellation fees. As of December 31, 2008, SWEPCo has capitalized construction costs of $252 million (including AFUDC) and has contractual construction commitments of an additional $99 million. As of December 31, 2008, if the plant had been cancelled, cancellation fees of $33 million would have been required in order to terminate the construction commitments. If SWEPCo cancels the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

**Turk Plant**

See “Turk Plant” section within “Arkansas Rate Matters” for disclosure.

**Arkansas Rate Matters**

**Turk Plant**

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with the Oklahoma Municipal Power Authority (OMPA), the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk Plant. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo’s portion estimated to cost $1.2 billion. If approved on a timely basis, the plant is expected to be in-service in 2012.

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC, (b) capping CO2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT’s order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT’s grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.
A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In November 2008, SWEPCo received the air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant’s permit is heard. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit.

In January 2008 and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor’s Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission’s final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission’s report, it could impact SWEPCo’s proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of December 31, 2008, SWEPCo has capitalized approximately $510 million of expenditures (including AFUDC) and has significant contractual construction commitments for an additional $727 million. As of December 31, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Arkansas Base Rate Filing

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to concurrently recover financing costs related to the Stall and Turk generation plants that are currently under construction. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

Stall Unit

See “Stall Unit” section within “Louisiana Rate Matters” for disclosure.
FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC’s direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the “lost revenues” reflected in the SECA rates should not have been 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 the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ’s initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ’s initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ’s findings on key issues are largely without merit. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ’s initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. In December 2008, an additional settlement agreement was approved by the FERC resulting in the completion of a $2 million settlement applicable to $17 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $9 million applicable to $92 million of SECA revenues. The balance in the reserve for future settlements as of December 2008 was $35 million. In-process settlements total $1 million applicable to $20 million of SECA revenues. In February 2009, the FERC approved the in-process settlements resulting in the completion of a $1 million settlement application to $20 million of SECA revenues.

If the FERC adopts the ALJ’s decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies’ retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP’s zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies’ future construction of new transmission facilities, net income and cash flows.
The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. The remaining 20% is being incurred by AEP until it can revise its rates in Indiana and Michigan to recover these lost revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of its portion of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP’s complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP’s request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in a combined increase in annual revenues for the AEP East companies of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of AEP's transmission facilities so that retail rates for jurisdictions other than Ohio are not affected. Retail rates for CSPCo and OPCo would be increased through the Transmission Cost Recovery Rider (TCRR) totaling approximately $10 million and $12 million, respectively. The TCRR includes a true-up mechanism so CSPCo’s and OPCo’s net income will not be adversely affected by a FERC ordered transmission rate increase. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP’s proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. In October 2008, AEP began settlement discussions and filed the required compliance filing. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology to be reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still
pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during this period. In December 2008, the AEP West companies recorded a provision for refund which had a $97 million unfavorable effect on AEP net income. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction refund to be made through the fuel clause recovery mechanism. PSO will begin refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. TCC and TNC in Texas and SWEPCo in Arkansas and Louisiana will be working with their state commissions to determine the effect the FERC order will have on retail rates. Management believes that the existing provision for refund is adequate to address existing and any future refunds that may result from the FERC order.

The table below lists the respective amounts the AEP East companies and the AEP West companies recorded in December 2008 including the net increase (decrease) to net income for the year ended December 31, 2008:

<table>
<thead>
<tr>
<th>AEP East Companies</th>
<th>Amounts to be (Transferred)/Received Including Interest</th>
<th>Increase/Decrease to Net Income</th>
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<tr>
<td>APCo</td>
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<td>$ (50)</td>
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<td>I&amp;M</td>
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<tr>
<td>OPCo</td>
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<td>(40)</td>
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<td>CSPCo</td>
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<td>(28)</td>
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<tr>
<td>KPCo</td>
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<td>(12)</td>
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<tr>
<td>Total – AEP East Companies</td>
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<td>(162)</td>
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<table>
<thead>
<tr>
<th>AEP West Companies</th>
<th>Amounts to be (Transferred)/Received Including Interest</th>
<th>Increase/Decrease to Net Income</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
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<td>$ 12</td>
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<td>SWEPCo</td>
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<td>TCC</td>
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<td>Total – AEP West Companies</td>
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<table>
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<tr>
<th>Total – AEP Consolidated</th>
<th>Amounts to be (Transferred)/Received Including Interest</th>
<th>Increase/Decrease to Net Income</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$ -</td>
<td>$ (97)</td>
</tr>
</tbody>
</table>

Management cannot predict the outcome of the requested FERC rehearing proceeding or any future regulatory proceedings but believes our provision regarding future regulatory proceedings is adequate.
5. **EFFECTS OF REGULATION**

Regulatory assets and liabilities are comprised of the following items:

<table>
<thead>
<tr>
<th>Regulatory Assets:</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Current Regulatory Asset</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under-recovered Fuel Costs</td>
<td>$ 284</td>
<td>$ 11</td>
<td>(c) (h)</td>
</tr>
<tr>
<td><strong>Noncurrent Regulatory Assets</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SFAS 158 Regulatory Asset (See Note 8)</td>
<td>$ 2,162</td>
<td>$ 659</td>
<td>(a) (g)</td>
</tr>
<tr>
<td>SFAS 109 Regulatory Asset, Net (See Note 12)</td>
<td>888</td>
<td>815</td>
<td>(e) (g)</td>
</tr>
<tr>
<td>Virginia E&amp;R Costs Recovery (See Note 4)</td>
<td>123</td>
<td>82</td>
<td>(c) (l)</td>
</tr>
<tr>
<td>Unamortized Loss on Reacquired Debt</td>
<td>104</td>
<td>108</td>
<td>(b) (l)</td>
</tr>
<tr>
<td>Oklahoma 2007 Ice Storms (See Note 4)</td>
<td>62</td>
<td>-</td>
<td>(b) (j)</td>
</tr>
<tr>
<td>Customer Choice Deferrals – Ohio (See Note 4)</td>
<td>55</td>
<td>52</td>
<td>(b) (o)</td>
</tr>
<tr>
<td>Restructuring Transition Costs – Texas, Ohio and Virginia</td>
<td>38</td>
<td>108</td>
<td>(a) (k)</td>
</tr>
<tr>
<td>Line Extension Carrying Costs – Ohio (See Note 4)</td>
<td>31</td>
<td>23</td>
<td>(b) (o)</td>
</tr>
<tr>
<td>Mountaineer Carbon Capture Project – Virginia (See Note 4)</td>
<td>29</td>
<td>-</td>
<td>(c) (o)</td>
</tr>
<tr>
<td>Hurricane Ike – Ohio (See Note 4)</td>
<td>27</td>
<td>-</td>
<td>(b) (o)</td>
</tr>
<tr>
<td>Cook Nuclear Plant Refueling Outage Levelization</td>
<td>25</td>
<td>34</td>
<td>(a) (d)</td>
</tr>
<tr>
<td>Hurricanes Dolly and Ike – Texas (See Note 4)</td>
<td>23</td>
<td>-</td>
<td>(b) (o)</td>
</tr>
<tr>
<td>Lawton Settlement – Oklahoma</td>
<td>21</td>
<td>32</td>
<td>(b) (i)</td>
</tr>
<tr>
<td>Red Rock Generating Facility – Oklahoma (See Note 4)</td>
<td>11</td>
<td>21</td>
<td>(b) (m)</td>
</tr>
<tr>
<td>Unrealized Loss on Forward Commitments</td>
<td>-</td>
<td>39</td>
<td>(a) (g)</td>
</tr>
<tr>
<td>Other</td>
<td>184</td>
<td>226</td>
<td>(c) (g)</td>
</tr>
<tr>
<td><strong>Total Noncurrent Regulatory Assets</strong></td>
<td>$ 3,783</td>
<td>$ 2,199</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Regulatory Liabilities:</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Current Regulatory Liability</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Over-recovered Fuel Costs (p)</td>
<td>$ 66</td>
<td>$ 64</td>
<td>(c) (h)</td>
</tr>
<tr>
<td><strong>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asset Removal Costs</td>
<td>$ 2,017</td>
<td>$ 1,927</td>
<td>(e)</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>294</td>
<td>311</td>
<td>(c) (n)</td>
</tr>
<tr>
<td>Excess ARO for Nuclear Decommissioning Liability (See Note 9)</td>
<td>208</td>
<td>362</td>
<td>(f)</td>
</tr>
<tr>
<td>Unrealized Gain on Forward Commitments</td>
<td>91</td>
<td>103</td>
<td>(a) (g)</td>
</tr>
<tr>
<td>Deferred State Income Taxes Due to the Phase Out of the Ohio Franchise Tax</td>
<td>-</td>
<td>43</td>
<td>(a) (h)</td>
</tr>
<tr>
<td>Other</td>
<td>179</td>
<td>206</td>
<td>(c) (g)</td>
</tr>
<tr>
<td><strong>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</strong></td>
<td>$ 2,789</td>
<td>$ 2,952</td>
<td></td>
</tr>
</tbody>
</table>

(a) Amount does not earn a return.
(b) Amount earns a return.
(c) A portion of this amount earns a return.
(d) Amortized and recovered over the period beginning with the commencement of an outage and ending with the beginning of the next outage.
(e) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(f) This is the difference in the cumulative amount of removal costs recovered through rates and the cumulative amount of ARO as measured by applying SFAS 143 “Accounting for Asset Retirement Obligations.” This amount earns a return, accrues monthly and will be paid when the nuclear plant is decommissioned.
(g) Recovery/refund period - various periods.
(h) Recovery/refund period - 1 year.
(i) Recovery/refund period - 2 years.
(j) Recovery/refund period - 5 years
(k) Recovery/refund period - up to 7 years.
(l) Recovery/refund period - up to 35 years.
(m) Recovery/refund period - 48 years.
(n) Recovery/refund period - up to 78 years.
(o) Recovery method and timing to be determined in future proceedings.
(p) Current Regulatory Liability - Over-recovered Fuel Costs are recorded in Other on our Consolidated Balance Sheets.
6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements.

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company, EIS, together with and/or in addition to various industry mutual and commercial insurance carriers.

See Note 9 for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on our net income, cash flows and financial condition.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. Budgeted construction expenditures for 2009 are $2.6 billion. In addition, we expect to invest approximately $50 million in our transmission joint ventures in 2009. Budgeted construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

Our subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination. We do not expect to incur penalty payments under these provisions that would materially affect our net income, cash flows or financial condition.

The following table summarizes our actual contractual commitments at December 31, 2008:

<table>
<thead>
<tr>
<th>Contractual Commitments</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$ 3,788</td>
<td>$ 4,832</td>
<td>$ 2,590</td>
<td>$ 7,362</td>
<td>$ 18,572</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>51</td>
<td>73</td>
<td>40</td>
<td>268</td>
<td>432</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>661</td>
<td>993</td>
<td>613</td>
<td>-</td>
<td>2,267</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 4,500</strong></td>
<td><strong>$ 5,898</strong></td>
<td><strong>$ 3,243</strong></td>
<td><strong>$ 7,630</strong></td>
<td><strong>$ 21,271</strong></td>
</tr>
</tbody>
</table>

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel. The longest contract extends to the year 2035. The contracts provide for periodic price adjustments and contain various clauses that would release us from our commitments under certain conditions.

(b) Represents contractual commitments for energy and capacity purchase contracts.

(c) Represents only capital assets that are contractual commitments.
GUARANTEES

We record certain immaterial liabilities for guarantees in accordance with FIN 45 “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.” In addition, we adopted FSP SFAS 133-1 and FIN 45-4 “Disclosures about Credit Derivatives and Certain Guarantees: An amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161” effective December 31, 2008. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At December 31, 2008, the maximum future payments for LOCs issued under the two $1.5 billion credit facilities are $62 million with maturities ranging from March 2009 to March 2010. The two $1.5 billion credit facilities were reduced by Lehman Brothers Holding Inc.’s commitment amount of $46 million following its bankruptcy.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of December 31, 2008, $372 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of December 31, 2008, SWEPCo has collected approximately $38 million through a rider for final mine closure costs, of which approximately $700 thousand is recorded in Other Current Liabilities, $20 million is recorded in Deferred Credits and Other and $18 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all its costs. SWEPCo passes these costs through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sales agreements is discussed in the “Dispositions” section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.2 billion. Approximately $1 billion of the maximum exposure relates to the Bank of America (BOA) litigation (see “Enron Bankruptcy” section of this note), of which the probable payment/performance risk is $433 million and is recorded in Deferred Credits and Other on our Consolidated Balance Sheets as of December 31, 2008. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.
Lease Obligations

We lease certain equipment under master lease agreements. See “Master Lease Agreements” and “Railcar Lease” sections of Note 13 for disclosure of lease residual value guarantees.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

In 2007, the U.S. District Court approved our consent decree with the Federal EPA, the DOJ, the states and the special interest groups. The consent decree resolved all issues related to various parties’ claims against us in the NSR cases. Under the consent decree, we paid a $15 million civil penalty in 2008 and provided $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation. We expensed these amounts in 2007.

In October 2008, the court approved a consent decree for a settlement reached with the Sierra Club in a case involving CSPCo’s share of jointly-owned units at the Stuart Station. The Stuart units, operated by DP&L, are equipped with SCR and FGD controls. Under the terms of the settlement, the joint-owners agreed to certain emission targets related to NOx, SO2 and PM. They also agreed to make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program. Another case involving a jointly-owned Beckjord unit had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, we might have for civil penalties under the pending CAA proceeding for Beckjord. We are also unable to predict the timing of resolution of these matters. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through future regulated rates or market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect our future net income, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in federal district court for the Eastern District of Texas alleging violations of the CAA at SWEPCo’s Welsh Plant. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs’ attorneys’ fees and costs. The consent decree was entered as a final order in June 2008.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. A permit alteration was issued in March 2007 that clarified or eliminated certain of the permit conditions. In June 2007, TCEQ denied a motion to overturn the permit alteration. The permit alteration was appealed to the Travis County District Court, but was resolved by entry of the consent decree in the federal citizen suit action, and dismissed with prejudice in July 2008. Notice of an administrative settlement of the TCEQ enforcement action was published in June 2008. The settlement requires SWEPCo to pay an administrative penalty of $49 thousand and to fund a supplemental environmental project in the amount of $49 thousand, and resolves all violations alleged by TCEQ. In October 2008, TCEQ approved the settlement.
In February 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that the permit alteration issued by TCEQ was improper. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit.

We are unable to predict the timing of any future action by the Federal EPA or the effect of such action on our net income, cash flows or financial condition.

**Carbon Dioxide Public Nuisance Claims**

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO₂ emissions from the defendants’ power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO₂ and other greenhouse gases under the CAA, which may impact the Second Circuit’s analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court’s decision on this case which we provided in 2007. We believe the actions are without merit and intend to defend against the claims.

**Alaskan Villages’ Claims**

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO₂ contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. We believe the action is without merit and intend to defend against the claims.

**The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation**

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2008, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for six sites for which alleged liability is unresolved. There are nine additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at four sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.
In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms. I&M recorded approximately $4 million of expense through December 31, 2008. As the remediation work is completed, I&M’s cost may increase. I&M cannot predict the amount of additional cost, if any. At present, our estimates do not anticipate material cleanup costs for this site.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites.

**Cook Plant Unit 1 Fire and Shutdown**

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. Our current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

The refueling outage for Cook Plant Unit 2, which continues to operate at full power, will take place as scheduled in the spring of 2009. The refueling outage scheduled for the fall of 2009 for Unit 1 is currently being evaluated. Management anticipates that the loss of capacity from Unit 1 will not affect I&M’s ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.

I&M maintains property insurance through NEIL with a $1 million deductible. As of December 31, 2008, we recorded $28 million in Prepayments and Other on our Consolidated Balance Sheet representing recoverable amounts under property insurance proceeds. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy effective December 15, 2008. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

In January 2009, I&M filed its regular semi-annual fuel filing in Indiana which determines the fuel rate for the period April 2009 through September 2009. I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the forecast period. I&M has deferred $9 million of accidental outage insurance proceeds as of December 31, 2008 which is included in Other Current Liabilities on our Consolidated Balance Sheet.
**TEM Litigation**

We agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement (PPA). Beginning May 1, 2003, we tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

In 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York.

In January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us $255 million. We recorded the $255 million as a pretax gain in January 2008 under Asset Impairments and Other Related Charges on our Consolidated Statements of Income. This settlement related to the Plaquemine Cogeneration Facility, which we impaired and sold in 2006.

**Enron Bankruptcy**

In 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron’s bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company that granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute is being litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

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

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. The lawsuit asserts that BOA made representations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron’s financial condition that BOA knew or should have known were false. In April 2005, the Judge in Texas entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. Trial in federal court in Texas was continued pending a decision on the motions for summary judgment in the New York case.

In August 2007, the judge in the New York action issued a decision granting BOA summary judgment and dismissing our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately $347 million ($427 million including interest at December 31, 2007). In August 2008, the court entered a final judgment of $346 million (the original judgment less $1 million BOA would have incurred to remove 55 BCF of natural gas from the Bammel storage facility) and clarified the interest calculation method. We appealed and posted a bond covering the amount of the judgment entered against us. The appeal was briefed during the first quarter of 2009.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. After recalculation for the final judgment, the liability for the BOA litigation was $433 million and $427 million including interest at December 31, 2008 and 2007, respectively. These liabilities are included in Deferred Credits and Other on our Consolidated Balance Sheets.
Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed in Federal District Court, Columbus, Ohio against AEP, certain executives and AEP’s ERISA Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. Two of the three actions were dropped voluntarily by the plaintiffs in those cases. In July 2006, the court entered judgment in the remaining case, denying plaintiff’s motion for class certification and dismissing all claims without prejudice. In August 2007, the appeals court reversed the trial court’s decision and held that the plaintiff did have standing to pursue his claim. The appeals court remanded the case to the trial court to consider the issue of whether the plaintiff is an adequate representative for the class of plan participants. In September 2008, the trial court denied the plaintiff’s motion for class certification and ordered briefing on whether the plaintiff may maintain an ERISA claim on behalf of the Plan in the absence of class certification. In October 2008, counsel for the plaintiff filed a motion to intervene on behalf of an individual seeking to intervene as a new plaintiff. We opposed this motion and will continue to defend against these claims.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In June 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we have for the remaining cases is adequate.

Rail Transportation Litigation

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied our motion to dismiss the case. We intend to vigorously defend against these allegations. We believe a provision recorded in 2008 should be sufficient.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were “high-priced.” The complaint alleged that we sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit’s remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. We believe a provision recorded in 2008 should be sufficient. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.
7. **ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS AND IMPAIRMENTS**

**ACQUISITIONS**

**2008**

*Erlbacher companies (AEP River Operations segment)*

In June 2008, AEP River Operations purchased certain barging assets from Missouri Barge Line Company, Missouri Dry Dock and Repair Company and Cape Girardeau Fleeting, Inc. (collectively known as Erlbacher companies) for $35 million. These assets were incorporated into AEP River Operations’ business which will diversify its customer base.

**2007**

*Darby Electric Generating Station (Utility Operations segment)*

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby Plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

*Lawrenceburg Generating Station (Utility Operations segment)*

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for $325 million and the assumption of liabilities of $3 million. AEGCo completed the purchase in May 2007. Lawrenceburg is located in Lawrenceburg, Indiana, adjacent to I&M’s Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW. AEGCo sells the power to CSPCo through a FERC-approved unit power agreement.

*Dresden Plant (Utility Operations segment)*

In August 2007, AEGCo agreed to purchase the partially completed Dresden Plant from Dominion Resources, Inc. for $85 million and the assumption of liabilities of $2 million. AEGCo completed the purchase in September 2007. AEGCo incurred approximately $78 million and $3 million in construction costs (excluding AFUDC) at the Dresden Plant in 2008 and 2007, respectively, and expects to incur approximately $142 million in additional costs (excluding AFUDC) prior to completion in 2013. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. When completed, the Dresden Plant will have a generating capacity of 580 MW.

**2006**

None

**DISPOSITIONS**

**2009**

*Electric Transmission Texas LLC (ETT) (Utility Operations segment)*

In January 2009, TCC sold $60 million of transmission facilities to ETT. See the 2007 activity for ETT below.

**2008**

None
2007

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In December 2007, TCC contributed $70 million of transmission facilities to ETT, a newly-formed affiliated entity which will own and operate transmission facilities in ERCOT. Through a series of transactions, we then sold, at net book value, a 50% equity ownership interest in ETT to a subsidiary of MidAmerican Energy Holdings Company.

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for $43 million plus capital adjustments. The sale did not impact net income.

Intercontinental Exchange, Inc. (ICE) (All Other)

In November 2000, we made our initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. During 2006, we sold approximately 600,000 shares and recognized a $39 million pretax gain ($25 million, net of tax). In March 2007, we sold 130,000 shares of ICE and recognized a $16 million pretax gain ($10 million, net of tax). We recorded the gains in Interest and Investment Income on our Consolidated Statements of Income for the year ended December 31, 2007. Our remaining investment of approximately 138,000 shares as of December 31, 2008 and 2007 is recorded in Other Temporary Investments on our Consolidated Balance Sheets.

Texas REPs (Utility Operations segment)

As part of the purchase power and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In 2007, we received the final earnings sharing payment of $20 million. We received $70 million in 2006 for our share of earnings. The payments are reflected in Gain on Disposition of Assets, Net on our Consolidated Statement of Income.

Sweeny Cogeneration Plant (Generation and Marketing segment)

In October 2007, we sold our 50% equity interest in Sweeny to ConocoPhillips for approximately $80 million, including working capital and the buyer’s assumption of project debt. The Sweeny Cogeneration Plant is a 480 MW cogeneration plant located within ConocoPhillips’ Sweeny refinery complex southwest of Houston, Texas. We were the managing partner of the plant, which is co-owned by General Electric Company. As a result of the sale, we recognized a $47 million pretax gain ($30 million, net of tax) in 2007, which is reflected in Gain on Disposition of Equity Investments, Net on our 2007 Consolidated Statement of Income.

In addition to the sale of our interest in Sweeny, we agreed to separately sell our purchase power contract for our share of power generated by Sweeny through 2014 for $11 million to ConocoPhillips. ConocoPhillips also agreed to assume certain related third-party power obligations. These transactions were completed in conjunction with the sale of our 50% equity interest in October 2007. As a result of this sale, we recognized an $11 million pretax gain ($7 million, net of tax) in 2007, which is included in Other revenues on our 2007 Consolidated Statement of Income. In 2007, we recognized a total of $58 million in pretax gains on the Sweeny transactions ($37 million, net of tax).

2006

Compresion Bajio S de R.L. de C.V. (All Other)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600 MW power plant in Mexico. We received an indicative offer for Bajio in September 2005, which resulted in a pretax other-than-temporary impairment charge of approximately $7 million in 2005. We completed the sale in February 2006 for approximately $29 million with no effect on our 2006 net income.
In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for $64 million. We recorded a pretax impairment of $209 million ($136 million, net of tax) in 2006 based on the terms of the agreement to sell the Facility to Dow. We recorded the impairment in Asset Impairments and Other Related Charges on our 2006 Consolidated Statement of Income. The Facility does not meet the criteria for discontinued operations reporting.

We completed the sale in 2006. Excluding the 2006 impairment of $209 million discussed above, the effect of the sale on our 2006 net income was not significant. In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years. Under this agreement, we recorded gross margin sharing of $13 million and $10 million during 2008 and 2007, respectively. These margins were recorded in Gain on Disposition of Assets, Net on our 2008 and 2007 Consolidated Statements of Income. As a result of the sale, Dow reduced an existing below-current-market long-term power supply contract with us in Texas by 50 MW and we retained the right to any judgment paid by TEM for breaching the original Power Purchase and Sale Agreement (PPA). In 2003, we filed that TEM breached the PPA. In January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us $255 million and we recorded the amount as a pretax gain under Asset Impairments and Other Related Charges on our Consolidated Statements of Income in 2008. See “TEM Litigation” section of Note 6.

**Intercontinental Exchange, Inc. (ICE) (All Other)**

See the above 2007 disclosure “Intercontinental Exchange, Inc. (ICE)” for information regarding sales in 2006.

**DISCONTINUED OPERATIONS**

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify those businesses or activities as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and are classified as such in 2008, 2007 and 2006. Results of operations of these businesses are classified as shown in the following table:

<table>
<thead>
<tr>
<th></th>
<th>SEEBOARD (a)</th>
<th>U.K. Generation (b)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008 Revenue</td>
<td>$ -</td>
<td>$ 2</td>
<td>$ 2</td>
</tr>
<tr>
<td>2008 Pretax Income</td>
<td>-</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>2008 Earnings, Net of Tax</td>
<td>-</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>2007 Revenue</td>
<td>$ -</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2007 Pretax Income</td>
<td>-</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>2007 Earnings, Net of Tax</td>
<td>4</td>
<td>20</td>
<td>24</td>
</tr>
<tr>
<td>2006 Revenue</td>
<td>$ -</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2006 Pretax Income</td>
<td>-</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>2006 Earnings, Net of Tax</td>
<td>5</td>
<td>5</td>
<td>10</td>
</tr>
</tbody>
</table>

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD, a former U.K. utility subsidiary of AEP that was sold in 2002.

(b) The 2008 amounts relate primarily to favorable income tax reserve adjustments. The 2007 amounts relate to tax adjustments from the sale. The 2006 amounts relate to a release of accrued liabilities for the London office sublease and tax adjustments from the sale.
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES

2008

We recorded $255 million as a pretax gain in January 2008 under Asset Impairments and Other Related Charges as a result of the settlement with TEM. See “Plaquemine Cogeneration Facility” section of this note for additional information.

2007

None

2006

We recorded a pretax impairment of assets totaling $209 million as a result of the terms of our agreement to sell the Plaquemine Cogeneration Facility to Dow. See “Plaquemine Cogeneration Facility” section of this note for additional information regarding this sale.

The categories of impairments and gains on dispositions include:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Asset Impairments and Other Related Charges (Pretax)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Plaquemine Cogeneration Facility</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 209</td>
</tr>
<tr>
<td>TEM Settlement</td>
<td>(255)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ (255)</td>
<td>$ -</td>
<td>$ 209</td>
</tr>
<tr>
<td><strong>Gain (Loss) on Disposition of Assets, Net (Pretax)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Texas REPs</td>
<td>$ -</td>
<td>$ 20</td>
<td>$ 70</td>
</tr>
<tr>
<td>Revenue Sharing on Plaquemine Cogeneration Facility</td>
<td>13</td>
<td>10</td>
<td>-</td>
</tr>
<tr>
<td>Gain on Sale of Land Rights and Other Miscellaneous Property, Plant and Equipment</td>
<td>3</td>
<td>11</td>
<td>(1)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 16</td>
<td>$ 41</td>
<td>$ 69</td>
</tr>
<tr>
<td><strong>Gain on Disposition of Equity Investments, Net (Pretax)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sweeny</td>
<td>$ -</td>
<td>$ 47</td>
<td>$ -</td>
</tr>
<tr>
<td>Other</td>
<td>-</td>
<td>-</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ -</td>
<td>$ 47</td>
<td>$ 3</td>
</tr>
</tbody>
</table>

8. BENEFIT PLANS

We sponsor two qualified pension plans that we merged at December 31, 2008 and two unfunded nonqualified pension plans. A substantial majority of our employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. We sponsor OPEB plans to provide medical and life insurance benefits for retired employees.

We adopted SFAS 158 in December 2006 and recognized the obligations associated with our defined benefit pension plans and OPEB plans in the balance sheets. We recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The effect of SFAS 158 on our 2006 financial statements was a pretax AOCI adjustment of $1,236 million that was offset by a SFAS 71 regulatory asset of $875 million and a deferred income tax asset of $126 million resulting in a net of tax AOCI equity reduction of $235 million.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating market conditions, investment returns and discount rates.
The following tables provide a reconciliation of the changes in the plans’ projected benefit obligations and fair value of assets over the two-year period ending at the plan’s measurement date of December 31, 2008, and their funded status as of December 31 of each year.

### Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2008 and 2007

<table>
<thead>
<tr>
<th>Change in Projected Benefit Obligation</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Projected Obligation at January 1</td>
<td>$ 4,109</td>
<td>$ 4,108</td>
</tr>
<tr>
<td>Service Cost</td>
<td>100</td>
<td>96</td>
</tr>
<tr>
<td>Interest Cost</td>
<td>249</td>
<td>235</td>
</tr>
<tr>
<td>Actuarial Loss (Gain)</td>
<td>139</td>
<td>(64)</td>
</tr>
<tr>
<td>Plan Amendments</td>
<td>-</td>
<td>18</td>
</tr>
<tr>
<td>Benefit Payments</td>
<td>(296)</td>
<td>(284)</td>
</tr>
<tr>
<td>Participant Contributions</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Medicare Subsidy</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Projected Obligation at December 31</td>
<td>$ 4,301</td>
<td>$ 4,109</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Change in Fair Value of Plan Assets</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fair Value of Plan Assets at January 1</td>
<td>$ 4,504</td>
<td>$ 4,346</td>
</tr>
<tr>
<td>Actual Gain (Loss) on Plan Assets</td>
<td>(1,054)</td>
<td>435</td>
</tr>
<tr>
<td>Company Contributions</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Participant Contributions</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Benefit Payments</td>
<td>(296)</td>
<td>(284)</td>
</tr>
<tr>
<td>Fair Value of Plan Assets at December 31</td>
<td>$ 3,161</td>
<td>$ 4,504</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Funded (Underfunded) Status at December 31</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$ (1,140)</td>
<td>$ 395</td>
</tr>
</tbody>
</table>

We have significant investments in several trust funds to provide for future pension and OPEB payments. All of our trust funds’ investments are diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds’ ability to make their required payments.

### Amounts Recognized on the Balance Sheets as of December 31, 2008 and 2007

<table>
<thead>
<tr>
<th>Amounts Recognized on the Balance Sheets as of December 31, 2008 and 2007</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Employee Benefits and Pension Assets – Prepaid Benefit Costs</td>
<td>$</td>
<td>- $ 482</td>
</tr>
<tr>
<td>Other Current Liabilities – Accrued Short-term Benefit Liability</td>
<td>(9)</td>
<td>(8)</td>
</tr>
<tr>
<td>Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability</td>
<td>(1,131)</td>
<td>(79)</td>
</tr>
<tr>
<td>Funded (Underfunded) Status</td>
<td>$ (1,140)</td>
<td>$ 395</td>
</tr>
</tbody>
</table>
## SFAS 158 Amounts Recognized in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2008, 2007 and 2006

### Other Postretirement Pension Plans

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Actuarial Loss</td>
<td>$2,024</td>
<td>$534</td>
<td>$759</td>
<td>$715</td>
<td>$231</td>
<td>$354</td>
</tr>
<tr>
<td>Prior Service Cost (Credit)</td>
<td>13</td>
<td>14</td>
<td>(5)</td>
<td>3</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Transition Obligation</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>70</td>
<td>97</td>
<td>124</td>
</tr>
<tr>
<td><strong>Pretax AOCI</strong></td>
<td>$2,037</td>
<td>$548</td>
<td>$754</td>
<td>$788</td>
<td>$332</td>
<td>$482</td>
</tr>
</tbody>
</table>

**Recorded as**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Assets</td>
<td>$1,660</td>
<td>$453</td>
<td>$582</td>
<td>$502</td>
<td>$204</td>
<td>$293</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>132</td>
<td>33</td>
<td>60</td>
<td>100</td>
<td>45</td>
<td>66</td>
</tr>
<tr>
<td>Net of Tax AOCI</td>
<td>245</td>
<td>62</td>
<td>112</td>
<td>186</td>
<td>83</td>
<td>123</td>
</tr>
<tr>
<td><strong>Pretax AOCI</strong></td>
<td>$2,037</td>
<td>$548</td>
<td>$754</td>
<td>$788</td>
<td>$332</td>
<td>$482</td>
</tr>
</tbody>
</table>

Components of the Change in Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007 are as follows:

### Pension Plans

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Actuarial Loss (Gain) During the Year</td>
<td>$1,527</td>
<td>$1,660</td>
<td>$1,660</td>
<td>$1,660</td>
</tr>
<tr>
<td>Amortization of Actuarial Loss</td>
<td>(37)</td>
<td>(59)</td>
<td>(59)</td>
<td>(59)</td>
</tr>
<tr>
<td>Prior Service Cost (Credit)</td>
<td>(1)</td>
<td>19</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Amortization of Transition Obligation</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Pretax AOCI Change for the Year</strong></td>
<td>$1,489</td>
<td>$2,037</td>
<td>$2,037</td>
<td>$2,037</td>
</tr>
</tbody>
</table>

### Other Postretirement Benefit Plans

<table>
<thead>
<tr>
<th>Components</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actuarial Loss (Gain) During the Year</td>
<td>$1,527</td>
<td>$1,660</td>
</tr>
<tr>
<td>Amortization of Actuarial Loss</td>
<td>(37)</td>
<td>(59)</td>
</tr>
<tr>
<td>Prior Service Cost (Credit)</td>
<td>(1)</td>
<td>19</td>
</tr>
<tr>
<td>Amortization of Transition Obligation</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Pretax AOCI Change for the Year</strong></td>
<td>$1,489</td>
<td>$2,037</td>
</tr>
</tbody>
</table>

### Pension and Other Postretirement Plans’ Assets

The asset allocations for our pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category, are as follows:

<table>
<thead>
<tr>
<th>Asset Category</th>
<th>Target Allocation</th>
<th>Percentage of Plan Assets at Year End</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
<td>2008</td>
</tr>
<tr>
<td>Equity Securities</td>
<td>55%</td>
<td>47%</td>
</tr>
<tr>
<td>Real Estate</td>
<td>5%</td>
<td>6%</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>39%</td>
<td>42%</td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>1%</td>
<td>5%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

The asset allocations for our OPEB plans at the end of 2008 and 2007, and target allocation for 2009, by asset category, are as follows:

<table>
<thead>
<tr>
<th>Asset Category</th>
<th>Target Allocation</th>
<th>Percentage of Plan Assets at Year End</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
<td>2008</td>
</tr>
<tr>
<td>Equity Securities</td>
<td>65%</td>
<td>53%</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>34%</td>
<td>43%</td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>1%</td>
<td>4%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>
Our investment strategy for our employee benefit trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the plans’ assets relative to the plans’ liabilities. To minimize investment risk, our employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Our investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. Our investment policies prohibit the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law, including ERISA.

The value of our pension plans’ assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007. The qualified plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of our OPEB plans’ assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007. The OPEB plans paid $120 million in benefits to plan participants during 2008.

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

<table>
<thead>
<tr>
<th>December 31,</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulated Benefit Obligation</td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Qualified Pension Plans</td>
<td>$4,119</td>
<td>$3,914</td>
</tr>
<tr>
<td>Nonqualified Pension Plans</td>
<td>80</td>
<td>77</td>
</tr>
<tr>
<td>Total</td>
<td>$4,199</td>
<td>$3,991</td>
</tr>
</tbody>
</table>

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2008 and 2007 were as follows:

<table>
<thead>
<tr>
<th>Underfunded Pension Plans</th>
<th>December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td></td>
<td>(in millions)</td>
</tr>
<tr>
<td>Projected Benefit Obligation</td>
<td>$4,301</td>
</tr>
<tr>
<td>Accumulated Benefit Obligation</td>
<td>$4,199</td>
</tr>
<tr>
<td>Fair Value of Plan Assets</td>
<td>3,161</td>
</tr>
<tr>
<td>Underfunded Accumulated Benefit Obligation</td>
<td>$1,038</td>
</tr>
</tbody>
</table>
Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of our benefit obligations are shown in the following tables:

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31,</td>
<td>December 31,</td>
</tr>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td>Discount Rate</td>
<td>6.00%</td>
<td>6.10%</td>
</tr>
<tr>
<td>Rate of Compensation Increase</td>
<td>5.90%</td>
<td>N/A</td>
</tr>
</tbody>
</table>

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

N/A = Not Applicable

To determine a discount rate, we use a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody’s Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2008, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2009 expected cash flows for the pension (qualified and nonqualified) and OPEB plans is as follows:

<table>
<thead>
<tr>
<th>Employer Contribution</th>
<th>Pension Plans (in millions)</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required Contributions (a)</td>
<td>$9</td>
<td>$4</td>
</tr>
<tr>
<td>Additional Discretionary Contributions</td>
<td>-</td>
<td>158</td>
</tr>
</tbody>
</table>

(a) Contribution required to meet minimum funding requirement under ERISA plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB plans’ periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.
The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants’ share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

<table>
<thead>
<tr>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pension Benefit Payments</td>
<td>Medicare Subsidy Receipts</td>
</tr>
<tr>
<td>(in millions)</td>
<td>(in millions)</td>
</tr>
<tr>
<td>2009</td>
<td>$378</td>
</tr>
<tr>
<td>2010</td>
<td>379</td>
</tr>
<tr>
<td>2011</td>
<td>377</td>
</tr>
<tr>
<td>2012</td>
<td>378</td>
</tr>
<tr>
<td>2013</td>
<td>384</td>
</tr>
<tr>
<td>Years 2014 to 2018, in Total</td>
<td>1,920</td>
</tr>
</tbody>
</table>

**Components of Net Periodic Benefit Cost**

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Years Ended December 31,</td>
<td></td>
</tr>
<tr>
<td>(in millions)</td>
<td>(in millions)</td>
</tr>
<tr>
<td>Service Cost</td>
<td>$100</td>
</tr>
<tr>
<td>Interest Cost</td>
<td>249</td>
</tr>
<tr>
<td>Expected Return on Plan Assets</td>
<td>(336)</td>
</tr>
<tr>
<td>Amortization of Transition Obligation</td>
<td>-</td>
</tr>
<tr>
<td>Amortization of Prior Service Cost (Credit)</td>
<td>1</td>
</tr>
<tr>
<td>Amortization of Net Actuarial Loss</td>
<td>37</td>
</tr>
<tr>
<td><strong>Net Periodic Benefit Cost</strong></td>
<td>51</td>
</tr>
<tr>
<td><strong>Net Periodic Benefit Cost Recognized as Expense</strong></td>
<td>$35</td>
</tr>
</tbody>
</table>

Estimated amounts expected to be amortized to net periodic benefit costs for our plans during 2009 are shown in the following table:

<table>
<thead>
<tr>
<th>Components</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Actuarial Loss</strong></td>
<td>$56</td>
<td>$46</td>
</tr>
<tr>
<td>Prior Service Cost</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Transition Obligation</td>
<td>-</td>
<td>27</td>
</tr>
<tr>
<td><strong>Total Estimated 2009 Pretax AOCI Amortization</strong></td>
<td>$57</td>
<td>$74</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Expected to be Recorded as</strong></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Asset</td>
<td>$46</td>
<td>$48</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>4</td>
<td>9</td>
</tr>
<tr>
<td>Net of Tax AOCI</td>
<td>7</td>
<td>17</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$57</td>
<td>$74</td>
</tr>
</tbody>
</table>
**Actuarial Assumptions for Net Periodic Benefit Costs**

The weighted-average assumptions as of January 1, used in the measurement of our benefit costs are shown in the following tables:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Discount Rate</strong></td>
<td>6.00%</td>
<td>5.75%</td>
<td>5.50%</td>
<td>6.20%</td>
<td>5.85%</td>
<td>5.65%</td>
</tr>
<tr>
<td><strong>Expected Return on Plan Assets</strong></td>
<td>8.00%</td>
<td>8.50%</td>
<td>8.50%</td>
<td>8.00%</td>
<td>8.00%</td>
<td>8.00%</td>
</tr>
<tr>
<td><strong>Rate of Compensation Increase</strong></td>
<td>5.90%</td>
<td>5.90%</td>
<td>5.90%</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

N/A = Not Applicable

The expected return on plan assets for 2008 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for OPEB plans measurement purposes are shown below:

<table>
<thead>
<tr>
<th>Health Care Trend Rates</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial</td>
<td>7.0%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Ultimate</td>
<td>5.0%</td>
<td>5.0%</td>
</tr>
<tr>
<td>Year Ultimate Reached</td>
<td>2012</td>
<td>2012</td>
</tr>
</tbody>
</table>

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

<table>
<thead>
<tr>
<th>1% Increase</th>
<th>1% Decrease</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in millions)</td>
<td>(in millions)</td>
</tr>
<tr>
<td>Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost</td>
<td>$</td>
</tr>
<tr>
<td>Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation</td>
<td>196</td>
</tr>
</tbody>
</table>

**American Electric Power System Retirement Savings Plan**

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. We provided matching contributions of 75% of the first 6% of eligible compensation contributed by an employee in 2008. Effective January 1, 2009, we match the first 1% of eligible employee contributions at 100% and the next 5% of contributions at 70%. The cost for company matching contributions totaled $71 million in 2008, $66 million in 2007 and $62 million in 2006.

**UMWA Benefits**

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions were not material in 2008, 2007 and 2006.
9. **NUCLEAR**

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S.

**Decommissioning and Low Level Waste Accumulation Disposal**

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2006. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $27 million in 2008, $32 million in 2007 and $30 million in 2006. Decommissioning costs recovered from customers are deposited in external trusts. The settlement agreement in I&M's base rate case will reduce the annual decommissioning cost recovery amount effective in 2009 to reflect the extension of the units’ operating licenses granted by the NRC.

I&M deposited an additional $4 million in 2008, 2007 and 2006 in its decommissioning trust under funding provisions approved by regulatory commissions. At December 31, 2008 and 2007, the total decommissioning trust fund balance was $959 million and $1.1 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

**SNF Disposal**

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2008 and 2007, fees and related interest of $264 million and $259 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $301 million and $285 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

**Trust Assets for Decommissioning and SNF Disposal**

We record securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. As discussed in the “Nuclear Trust Funds” section of Note 1, we record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions’ liabilities. Regulatory approval is required to withdraw decommissioning funds.

See “SFAS 157 Fair Value Measurements” section of Note 11 for disclosure of the fair value of assets within the trusts.
The following is a summary of nuclear trust fund investments at December 31:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Estimated Fair Value</td>
<td>Gross Unrealized Gains</td>
</tr>
<tr>
<td>Cash</td>
<td>$ 18</td>
<td>$ -</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>773</td>
<td>52</td>
</tr>
<tr>
<td>Equity Securities</td>
<td>469</td>
<td>89</td>
</tr>
<tr>
<td>Spent Nuclear Fuel and Decommissioning Trusts</td>
<td>$ 1,260</td>
<td>$ 141</td>
</tr>
</tbody>
</table>

Proceeds from sales of nuclear trust fund investments were $732 million, $696 million and $631 million in 2008, 2007 and 2006, respectively. Purchases of nuclear trust fund investments were $804 million, $777 million and $692 million in 2008, 2007 and 2006, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $33 million, $15 million and $7 million in 2008, 2007 and 2006, respectively. Gross realized losses from the sales of nuclear trust fund investments were $7 million, $5 million and $7 million in 2008, 2007 and 2006, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2008 was as follows:

<table>
<thead>
<tr>
<th>Fair Value of Debt Securities (in millions)</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Within 1 year</td>
<td>$ 51</td>
</tr>
<tr>
<td>1 year – 5 years</td>
<td>172</td>
</tr>
<tr>
<td>5 years – 10 years</td>
<td>209</td>
</tr>
<tr>
<td>After 10 years</td>
<td>341</td>
</tr>
<tr>
<td>Total</td>
<td>$ 773</td>
</tr>
</tbody>
</table>

**Nuclear Incident Liability**

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $37 million for I&M which is assessable if the insurer’s financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.5 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, we are initially covered for the first $300 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, we would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.
10. BUSINESS SEGMENTS

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

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

AEP River Operations
- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 13% for steel and 19% for other commodities. Effective July 30, 2008, AEP MEMCO LLC’s name was changed to AEP River Operations LLC.

Generation and Marketing
- Wind farms and marketing and risk management activities primarily in ERCOT. Our 50% interest in Sweeny Cogeneration Plant was sold in October 2007. See “Sweeny Cogeneration Plant” section of Note 7.

The remainder of our company’s activities is presented as All Other. While not considered a business segment, All Other includes:

- Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See “Plaquemine Cogeneration Facility” section of Note 7.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.
The tables below present our reportable segment information for the years ended December 31, 2008, 2007 and 2006 and balance sheet information as of December 31, 2008 and 2007. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year’s segment presentation. See “FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” (FSP FIN 39-1)” section of Note 2 for discussion of changes in netting certain balance sheet amounts.

### Year Ended December 31, 2008

<table>
<thead>
<tr>
<th></th>
<th>Nonutility Operations</th>
<th>Utility Operations</th>
<th>AEP River Operations and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Revenues</strong></td>
<td>$13,566 (e)</td>
<td>$13,566</td>
<td>$646</td>
<td>$363</td>
<td>$14,440</td>
<td>14,440</td>
</tr>
<tr>
<td><strong>Depreciation and Amortization</strong></td>
<td>$1,450</td>
<td>$1,450</td>
<td>$14</td>
<td>$28</td>
<td>$1,483</td>
<td>$1,483</td>
</tr>
<tr>
<td><strong>Interest Income</strong></td>
<td>$42</td>
<td>$42</td>
<td>-</td>
<td>$28</td>
<td>(65)</td>
<td>56</td>
</tr>
<tr>
<td><strong>Interest Expense</strong></td>
<td>$916</td>
<td>$916</td>
<td>5</td>
<td>$22</td>
<td>958</td>
<td>-</td>
</tr>
<tr>
<td><strong>Income Tax Expense</strong></td>
<td>$515</td>
<td>$515</td>
<td>26</td>
<td>$17</td>
<td>642</td>
<td>-</td>
</tr>
<tr>
<td><strong>Income Before Discontinued Operations and Extraordinary Loss</strong></td>
<td>$1,115</td>
<td>$1,115</td>
<td>$55</td>
<td>$65</td>
<td>$1,368</td>
<td>$1,368</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>$1,115</td>
<td>$1,115</td>
<td>$55</td>
<td>$65</td>
<td>$1,380</td>
<td>$1,380</td>
</tr>
<tr>
<td></td>
<td>$3,871</td>
<td>$3,871</td>
<td>$116</td>
<td>$2</td>
<td>$3,960</td>
<td>$3,960</td>
</tr>
</tbody>
</table>

### Year Ended December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>Nonutility Operations</th>
<th>Utility Operations</th>
<th>AEP River Operations and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Revenues</strong></td>
<td>$12,655</td>
<td>$12,655</td>
<td>$537</td>
<td>$302</td>
<td>$13,380</td>
<td>13,380</td>
</tr>
<tr>
<td><strong>Depreciation and Amortization</strong></td>
<td>$1,483</td>
<td>$1,483</td>
<td>$11</td>
<td>$29</td>
<td>$1,513</td>
<td>-</td>
</tr>
<tr>
<td><strong>Interest Income</strong></td>
<td>$21</td>
<td>$21</td>
<td>-</td>
<td>$3</td>
<td>35</td>
<td>-</td>
</tr>
<tr>
<td><strong>Interest Expense</strong></td>
<td>$787</td>
<td>$787</td>
<td>5</td>
<td>$28</td>
<td>841</td>
<td>-</td>
</tr>
<tr>
<td><strong>Income Tax Expense (Credit)</strong></td>
<td>$486</td>
<td>$486</td>
<td>35</td>
<td>$10</td>
<td>516</td>
<td>-</td>
</tr>
<tr>
<td><strong>Income (Loss) Before Discontinued Operations and Extraordinary Loss</strong></td>
<td>$1,031</td>
<td>$1,031</td>
<td>$61</td>
<td>$67</td>
<td>$1,144</td>
<td>-</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>$952</td>
<td>$952</td>
<td>$61</td>
<td>$67</td>
<td>$1,089</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>$4,050</td>
<td>$4,050</td>
<td>$12</td>
<td>$2</td>
<td>$4,068</td>
<td>-</td>
</tr>
</tbody>
</table>

(a) Reconciling adjustments for the change in netting certain balance sheet amounts.

(b) Includes interest income from discontinued operations.

(c) Includes interest expense from discontinued operations, net of income tax and extraordinary loss.

(d) Includes interest income from extraordinary loss.

(e) Includes interest expense from extraordinary loss.

FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” (FSP FIN 39-1)” section of Note 2 for discussion of changes in netting certain balance sheet amounts.
### Year Ended December 31, 2006

#### Revenues from:

<table>
<thead>
<tr>
<th>Source</th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>AEP River Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>External Customers</td>
<td>$ 12,066</td>
<td>$ 520</td>
<td>$ 62</td>
<td>(26)</td>
<td>$ -</td>
<td>$</td>
<td>$ 12,622</td>
</tr>
<tr>
<td>Other Operating Segments</td>
<td>(55)</td>
<td>-</td>
<td>-</td>
<td>97</td>
<td>(54)</td>
<td></td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Revenues</strong></td>
<td>$ 12,011</td>
<td>$ 532</td>
<td>$ 62</td>
<td>$ 71</td>
<td>(54)</td>
<td>$</td>
<td>$ 12,622</td>
</tr>
</tbody>
</table>

#### Depreciation and Amortization

<table>
<thead>
<tr>
<th>Source</th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>AEP River Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest Income</td>
<td>36</td>
<td>-</td>
<td>2</td>
<td>91</td>
<td>(68)</td>
<td></td>
<td>61</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>667</td>
<td>4</td>
<td>11</td>
<td>118</td>
<td>(68)</td>
<td></td>
<td>732</td>
</tr>
<tr>
<td>Income Tax Expense (Credit)</td>
<td>543</td>
<td>42</td>
<td>(19)</td>
<td>(81)</td>
<td>-</td>
<td></td>
<td>485</td>
</tr>
</tbody>
</table>

#### Income (Loss) Before Discontinued Operations and Extraordinary Loss

<table>
<thead>
<tr>
<th>Source</th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>AEP River Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Property, Plant and Equipment – Net</td>
<td>$ 1,028</td>
<td>$ 80</td>
<td>$ 12</td>
<td>(128)</td>
<td>$ -</td>
<td></td>
<td>$ 992</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
<td>-</td>
</tr>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>$ 1,028</td>
<td>$ 80</td>
<td>$ 12</td>
<td>(128)</td>
<td>$ -</td>
<td></td>
<td>$ 1,002</td>
</tr>
</tbody>
</table>

#### Gross Property Additions

<table>
<thead>
<tr>
<th>Source</th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>AEP River Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Property Additions</td>
<td>$ 3,494</td>
<td>$ 7</td>
<td>$ 1</td>
<td>26 (c)</td>
<td>$ -</td>
<td></td>
<td>$ 3,528</td>
</tr>
</tbody>
</table>

### December 31, 2008

#### Total Property, Plant and Equipment

<table>
<thead>
<tr>
<th>Source</th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>AEP River Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Property, Plant and Equipment – Net</td>
<td>$ 48,997</td>
<td>$ 371</td>
<td>$ 565</td>
<td>$ 10</td>
<td>(233)</td>
<td></td>
<td>$ 49,710</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>16,525</td>
<td>73</td>
<td>140</td>
<td>8</td>
<td>(23)</td>
<td></td>
<td>16,723</td>
</tr>
</tbody>
</table>

#### Total Assets

<table>
<thead>
<tr>
<th>Source</th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>AEP River Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Assets</td>
<td>$ 43,773</td>
<td>$ 439</td>
<td>$ 737</td>
<td>$ 14,501</td>
<td>(14,295)</td>
<td>(d)</td>
<td>$ 45,155</td>
</tr>
<tr>
<td>Investments in Equity Method Subsidiaries</td>
<td>22</td>
<td>2</td>
<td>-</td>
<td>-</td>
<td></td>
<td>-</td>
<td>24</td>
</tr>
</tbody>
</table>
### December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>Utility Operations</th>
<th>Nonutility Operations</th>
<th>Generation and Marketing</th>
<th>All Other (a)</th>
<th>Reconciling Adjustments (b)</th>
<th>Consolidated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Property, Plant and Equipment</strong></td>
<td>$45,514</td>
<td>$263</td>
<td>$567</td>
<td>$38</td>
<td>$(237)</td>
<td>$46,145</td>
</tr>
<tr>
<td><strong>Accumulated Depreciation and Amortization</strong></td>
<td>16,107</td>
<td>61</td>
<td>112</td>
<td>7</td>
<td>(12)</td>
<td>16,275</td>
</tr>
<tr>
<td><strong>Total Property, Plant and Equipment – Net</strong></td>
<td>$29,407</td>
<td>$202</td>
<td>$455</td>
<td>$31</td>
<td>$(225)</td>
<td>$29,870</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$39,298</td>
<td>$340</td>
<td>$697</td>
<td>$12,117</td>
<td>$(12,133)(d)</td>
<td>$40,319</td>
</tr>
<tr>
<td><strong>Investments in Equity Method Subsidiaries</strong></td>
<td>14</td>
<td>2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>16</td>
</tr>
</tbody>
</table>

(a) All Other includes:
- Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See “Plaquemine Cogeneration Facility” section of Note 7.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(b) Includes eliminations due to an intercompany capital lease which began in the first quarter of 2007.

(c) Gross Property Additions for All Other includes construction expenditures of $8 million, $4 million and $25 million in 2008, 2007 and 2006, respectively, related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines were refurbished and transferred to a generating facility within our Utility Operations segment in the fourth quarter of 2008. The transfer of these turbines resulted in the elimination of $37 million from All Other and the addition of $37 million to Utility Operations.

(d) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP’s investments in subsidiary companies.

(e) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This is offset by the Utility Operations segment’s related net sales (purchases) for these contracts to AEPEP in Revenues from Other Operating Segments of $122 million and $406 million for the years ended December 31, 2008 and 2007, respectively. The Generation and Marketing segment also reports these purchases or sales contracts with Utility Operations as Revenues from Other Operating Segments.

### 11. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

#### DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty will fail to perform to the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract’s term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for longer term contracts.
Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Net Income during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

**Fair Value Hedging Strategies**

At certain times, we enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Consolidated Statements of Income. During 2008, 2007 and 2006, we recognized no hedge ineffectiveness related to these derivative transactions.

**Cash Flow Hedging Strategies**

We enter into, and designate as cash flow hedges, certain derivative transactions for the purchase and sale of electricity, coal and natural gas (collectively “Power”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect margins for a portion of future electricity sales and fuel or energy purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Consolidated Statements of Income, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2008, 2007 and 2006, we recognized immaterial amounts in Net Income related to hedge ineffectiveness.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. We reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2008, 2007 and 2006, we recognized immaterial amounts in Net Income related to hedge ineffectiveness.
At times, we are exposed to foreign currency exchange rate risks primarily because we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Other Operation and Maintenance expense on our Consolidated Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure. During 2008, 2007 and 2006, we recognized no hedge ineffectiveness related to these derivative transactions.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2008 were:

<table>
<thead>
<tr>
<th>Hedging Assets (a)</th>
<th>Hedging Liabilities (a)</th>
<th>Accumulated Other Comprehensive Income (Loss) After Tax</th>
<th>Portion Expected to be Reclassified to Net Income During the Next Twelve Months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power</td>
<td>$ 34</td>
<td>$ (23)</td>
<td>$ 7</td>
</tr>
<tr>
<td>Interest Rate</td>
<td>-</td>
<td>$ (8)</td>
<td>$ (29)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 34</strong></td>
<td><strong>$ (31)</strong></td>
<td><strong>$ (22)</strong></td>
</tr>
</tbody>
</table>

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2007 were:

<table>
<thead>
<tr>
<th>Hedging Assets (a)</th>
<th>Hedging Liabilities (a)</th>
<th>Accumulated Other Comprehensive Income (Loss) After Tax</th>
<th>Portion Expected to be Reclassified to Net Income During the Next Twelve Months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power</td>
<td>$ 9</td>
<td>$ (10)</td>
<td>$ (1)</td>
</tr>
<tr>
<td>Interest Rate</td>
<td>-</td>
<td>$ (3)</td>
<td>$ (25)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 9</strong></td>
<td><strong>$ (13)</strong></td>
<td><strong>$ (26)</strong></td>
</tr>
</tbody>
</table>

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2008, the maximum length of time that we are hedging (with SFAS 133 designated contracts) our exposure to variability in future cash flows related to forecasted transactions is 47 months.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2008:

<table>
<thead>
<tr>
<th>Amount</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Balance at December 31, 2005</strong></td>
<td>$ (27)</td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>13</td>
</tr>
<tr>
<td>Reclasses from AOCI to Net Income</td>
<td>8</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2006</strong></td>
<td>(6)</td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>(5)</td>
</tr>
<tr>
<td>Reclasses from AOCI to Net Income</td>
<td>(15)</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2007</strong></td>
<td>(26)</td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>(3)</td>
</tr>
<tr>
<td>Reclasses from AOCI to Net Income</td>
<td>7</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2008</strong></td>
<td>$ (22)</td>
</tr>
</tbody>
</table>
Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. We limit our credit risk by maintaining stringent credit policies whereby we assess a counterparty’s creditworthiness prior to transacting with them and continue to assess their creditworthiness on an ongoing basis. We employ the use of standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure is exceeded in excess of an established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements also provide that the failure or inability to post collateral is sufficient cause for termination and liquidation of all positions.

FAIR VALUE MEASUREMENTS

SFAS 107 Fair Value Measurements

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt at December 31, 2008 and 2007 are summarized in the following tables:

<table>
<thead>
<tr>
<th></th>
<th>December 31,</th>
<th></th>
<th>December 31,</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Book Value</td>
<td>Fair Value</td>
<td></td>
<td>Book Value</td>
<td>Fair Value</td>
</tr>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Long-term Debt</td>
<td>$15,983</td>
<td>$15,113</td>
<td>$14,994</td>
<td>$14,917</td>
</tr>
</tbody>
</table>
Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivative fair values are verified using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets or valued using pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer’s energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. We use a consistent modeling approach to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions or FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. In certain instances, the fair values of the transactions included in level 3 that use internally developed model inputs are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.
The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

### Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

<table>
<thead>
<tr>
<th>Assets:</th>
<th>Level 1</th>
<th>Level 2</th>
<th>Level 3</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cash and Cash Equivalents</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents (a)</td>
<td>$ 304</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 60</td>
<td>$ 364</td>
</tr>
<tr>
<td>Debt Securities (b)</td>
<td>-</td>
<td>47</td>
<td>-</td>
<td>-</td>
<td>47</td>
</tr>
<tr>
<td><strong>Total Cash and Cash Equivalents</strong></td>
<td>$ 304</td>
<td>47</td>
<td>-</td>
<td>60</td>
<td>411</td>
</tr>
<tr>
<td><strong>Other Temporary Investments</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents (c)</td>
<td>217</td>
<td>-</td>
<td>-</td>
<td>26</td>
<td>243</td>
</tr>
<tr>
<td>Debt Securities (d)</td>
<td>56</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>56</td>
</tr>
<tr>
<td>Equity Securities (e)</td>
<td>28</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>28</td>
</tr>
<tr>
<td><strong>Total Other Temporary Investments</strong></td>
<td>301</td>
<td>-</td>
<td>-</td>
<td>26</td>
<td>327</td>
</tr>
<tr>
<td><strong>Risk Management Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (f)</td>
<td>61</td>
<td>2,413</td>
<td>86</td>
<td>(2,022)</td>
<td>538</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (f)</td>
<td>6</td>
<td>32</td>
<td>-</td>
<td>(4)</td>
<td>34</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (g)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td><strong>Total Risk Management Assets</strong></td>
<td>67</td>
<td>2,445</td>
<td>86</td>
<td>(1,987)</td>
<td>611</td>
</tr>
<tr>
<td><strong>Spent Nuclear Fuel and Decommissioning Trusts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents (h)</td>
<td>-</td>
<td>6</td>
<td>-</td>
<td>12</td>
<td>18</td>
</tr>
<tr>
<td>Debt Securities (i)</td>
<td>-</td>
<td>773</td>
<td>-</td>
<td>-</td>
<td>773</td>
</tr>
<tr>
<td>Equity Securities (e)</td>
<td>469</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>469</td>
</tr>
<tr>
<td><strong>Total Spent Nuclear Fuel and Decommissioning Trusts</strong></td>
<td>469</td>
<td>779</td>
<td>-</td>
<td>12</td>
<td>1,260</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$ 1,141</td>
<td>$ 3,271</td>
<td>$ 86</td>
<td>(1,889)</td>
<td>$ 2,609</td>
</tr>
</tbody>
</table>

| Liabilities:                  |         |         |         |       |       |
| **Risk Management Liabilities** |         |         |         |       |       |
| Risk Management Contracts (f) | $ 77    | $ 2,213 | $ 37    | (2,054) | $ 273 |
| Cash Flow and Fair Value Hedges (f) | 1   | 34      | -       | (4)   | 31    |
| **Total Risk Management Liabilities** | $ 78  | $ 2,247 | $ 37    | (2,058) | $ 304 |

(a) Amounts in “Other” column primarily represent cash deposits in bank accounts with financial institutions. Level 1 amounts primarily represent investments in money market funds.

(b) Amount represents commercial paper investments with maturities of less than ninety days.

(c) Amounts in “Other” column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

(d) Amounts represent debt-based mutual funds.

(e) Amount represents publicly traded equity securities and equity-based mutual funds.

(f) Amounts in “Other” column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(g) “Dedesignated Risk Management Contracts” are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into Utility Operations Revenues over the remaining life of the contract.

(h) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(i) Amounts represent corporate, municipal and treasury bonds.
The following table sets forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as level 3 in the fair value hierarchy:

<table>
<thead>
<tr>
<th>Year Ended December 31, 2008</th>
<th>Net Risk Management Assets (Liabilities)</th>
<th>Other Temporary Investments (in millions)</th>
<th>Investments in Debt Securities</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Balance as of January 1, 2008</strong></td>
<td>$49</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>Realized (Gain) Loss Included in Net Income (or Changes in Net Assets)</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)</td>
<td>12</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>Purchases, Issuances and Settlements (b)</td>
<td>$-</td>
<td>(118)</td>
<td>(17)</td>
</tr>
<tr>
<td>Transfers in and/or out of Level 3 (c)</td>
<td>(36)</td>
<td>118</td>
<td>17</td>
</tr>
<tr>
<td>Changes in Fair Value Allocated to Regulated Jurisdictions (d)</td>
<td>24</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td><strong>Balance as of December 31, 2008</strong></td>
<td>$49</td>
<td>$-</td>
<td>$-</td>
</tr>
</tbody>
</table>

(a) Included in revenues on our Consolidated Statements of Income.
(b) Includes principal amount of securities settled during the period.
(c) “Transfers in and/or out of Level 3” represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

12. **INCOME TAXES**

The details of our consolidated income taxes before discontinued operations and extraordinary loss as reported are as follows:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>$164</td>
<td>$464</td>
<td>$429</td>
</tr>
<tr>
<td>Deferred</td>
<td>456</td>
<td>35</td>
<td>5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>620</td>
<td>499</td>
<td>434</td>
</tr>
<tr>
<td><strong>State and Local:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>(1)</td>
<td>1</td>
<td>61</td>
</tr>
<tr>
<td>Deferred</td>
<td>22</td>
<td>16</td>
<td>(10)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>21</td>
<td>17</td>
<td>51</td>
</tr>
<tr>
<td><strong>International:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Deferred</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss</strong></td>
<td>$642</td>
<td>$516</td>
<td>$485</td>
</tr>
</tbody>
</table>
The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

<table>
<thead>
<tr>
<th></th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>Net Income</td>
<td>$1,380</td>
</tr>
<tr>
<td>Discontinued Operations (Net of Income Tax of $(10), $(18) and $(1) Million in 2008, 2007 and 2006, respectively)</td>
<td>(12)</td>
</tr>
<tr>
<td>Extraordinary Loss, (Net of Income Tax of $39 Million in 2007)</td>
<td>-</td>
</tr>
<tr>
<td>Preferred Stock Dividends</td>
<td>3</td>
</tr>
<tr>
<td>Income Before Preferred Stock Dividends of Subsidiaries</td>
<td>1,371</td>
</tr>
<tr>
<td>Income Tax Expense Before Discontinued Operations and Extraordinary Loss</td>
<td>642</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td><strong>$2,013</strong></td>
</tr>
<tr>
<td>Income Taxes on Pretax Income at Statutory Rate (35%)</td>
<td>$705</td>
</tr>
</tbody>
</table>

Increase (Decrease) in Income Taxes resulting from the following items:

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depreciation</td>
<td>23</td>
<td>29</td>
<td>38</td>
</tr>
<tr>
<td>Investment Tax Credits, Net</td>
<td>(19)</td>
<td>(24)</td>
<td>(29)</td>
</tr>
<tr>
<td>Energy Production Credits</td>
<td>(20)</td>
<td>(18)</td>
<td>(19)</td>
</tr>
<tr>
<td>State Income Taxes</td>
<td>13</td>
<td>11</td>
<td>33</td>
</tr>
<tr>
<td>Removal Costs</td>
<td>(21)</td>
<td>(21)</td>
<td>(15)</td>
</tr>
<tr>
<td>AFUDC</td>
<td>(24)</td>
<td>(18)</td>
<td>(18)</td>
</tr>
<tr>
<td>Medicare Subsidy</td>
<td>(12)</td>
<td>(12)</td>
<td>(12)</td>
</tr>
<tr>
<td>Tax Reserve Adjustments</td>
<td>2</td>
<td>(8)</td>
<td>9</td>
</tr>
<tr>
<td>Other</td>
<td>(5)</td>
<td>(5)</td>
<td>(20)</td>
</tr>
<tr>
<td><strong>Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss</strong></td>
<td><strong>$642</strong></td>
<td><strong>$516</strong></td>
<td><strong>$485</strong></td>
</tr>
</tbody>
</table>

**Effective Income Tax Rate**

31.9% 31.0% 32.8%

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

<table>
<thead>
<tr>
<th></th>
<th>December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Deferred Tax Assets</td>
<td>$2,632</td>
</tr>
<tr>
<td>Deferred Tax Liabilities</td>
<td>(7,750)</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td><strong>$ (5,118)</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property-Related Temporary Differences</td>
<td>$(3,718)</td>
<td>$(3,300)</td>
</tr>
<tr>
<td>Amounts Due from Customers for Future Federal Income Taxes</td>
<td>(218)</td>
<td>(202)</td>
</tr>
<tr>
<td>Deferred State Income Taxes</td>
<td>(362)</td>
<td>(324)</td>
</tr>
<tr>
<td>Securitized Transition Assets</td>
<td>(776)</td>
<td>(806)</td>
</tr>
<tr>
<td>Regulatory Assets</td>
<td>(871)</td>
<td>(225)</td>
</tr>
<tr>
<td>Accrued Pensions</td>
<td>284</td>
<td>(211)</td>
</tr>
<tr>
<td>Deferred Income Taxes on Other Comprehensive Loss</td>
<td>240</td>
<td>83</td>
</tr>
<tr>
<td>Accrued Nuclear Decommissioning</td>
<td>(277)</td>
<td>(286)</td>
</tr>
<tr>
<td>Deferred Fuel</td>
<td>(76)</td>
<td>(19)</td>
</tr>
<tr>
<td>All Other, Net</td>
<td>656</td>
<td>551</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td><strong>$ (5,118)</strong></td>
<td><strong>$ (4,739)</strong></td>
</tr>
</tbody>
</table>

We, along with our subsidiaries, file a consolidated federal income tax return. The allocation of the AEP System’s current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.
We are no longer subject to U.S. federal examination for years before 2000. We have completed the exam for the years 2001 through 2003 and have issues that we are pursuing at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management’s opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

Prior to the adoption of FIN 48, we recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48 on January 1, 2007, we began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation and Maintenance. The impact of this interpretation was an unfavorable adjustment to the 2007 opening balance of retained earnings of $17 million. We reported $10 million and $2 million of interest expense, $21 million and $5 million of interest income and reversed $13 million and $17 million of prior period interest expense in 2008 and 2007, respectively. We had approximately $33 million for the receipt of interest accrued at December 31, 2008 and approximately $26 million and $16 million for the payment of interest and penalties accrued at December 31, 2008 and 2007, respectively.

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

<table>
<thead>
<tr>
<th></th>
<th>2008 (in millions)</th>
<th>2007 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance at January 1,</td>
<td>$ 222</td>
<td>$ 175</td>
</tr>
<tr>
<td>Increase - Tax Positions Taken During a Prior Period</td>
<td>41</td>
<td>75</td>
</tr>
<tr>
<td>Decrease - Tax Positions Taken During a Prior Period</td>
<td>(45)</td>
<td>(43)</td>
</tr>
<tr>
<td>Increase - Tax Positions Taken During the Current Year</td>
<td>27</td>
<td>20</td>
</tr>
<tr>
<td>Decrease - Tax Positions Taken During the Current Year</td>
<td>(5)</td>
<td>-</td>
</tr>
<tr>
<td>Increase - Settlements with Taxing Authorities</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Decrease - Lapse of the Applicable Statute of Limitations</td>
<td>(6)</td>
<td>(7)</td>
</tr>
<tr>
<td><strong>Balance at December 31,</strong></td>
<td><strong>$ 237</strong></td>
<td><strong>$ 222</strong></td>
</tr>
</tbody>
</table>

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $147 million. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

**Federal Tax Legislation**

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. We announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. We filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was allocated credits during this round of credit awards. After one of the original credit recipients surrendered its credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. We filed a new application in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits.

The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $200 million.

In October 2008, the Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law. The 2008 Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits and energy efficient commercial building deductions. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

In February 2009, the American Recovery and Reinvestment Tax Act of 2009 (the 2009 Act) was signed into law. The 2009 Act extended the bonus depreciation deduction for one year and provides for a long-term extension of the renewable production tax credit for wind energy and other properties. The 2009 Act also establishes a new investment tax credit for the manufacture of advanced energy property as well as appropriations for advanced energy research projects, carbon capture and storage and gridSMART technology. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income or financial condition, but is expected to have a positive material impact on cash flows.

**State Tax Legislation**

In June 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes phase in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities of $83 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Tax Expense and, for the Ohio companies, established a regulatory liability for $57 million pending rate-making treatment in Ohio. See “Ormet” section of Note 4 for further discussion. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by $22 million. In November 2006, the PUCO ordered that the $57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet. At December 31, 2008, the $57 million regulatory liability was fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this new tax, expenses of approximately $9 million, $6 million and $4 million were recorded in 2008, 2007 and 2006, respectively, in Taxes Other Than Income Taxes.

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the law reduced Texas income tax rates and was effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109. Based on the new law, we reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006, we recorded a net reduction to Deferred Income Taxes on our Consolidated Balance Sheet of $48 million of which $2 million was credited to Income Tax Expense and $46 million was credited to Regulatory Assets based upon the related rate-making treatment.
In July 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan’s principal business tax. The new law is effective January 1, 2008 and replaces the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

In September 2007, the Governor of Michigan signed House Bill 5198 which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis differences triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15-year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. We have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect our net income, cash flows or financial condition.

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

<table>
<thead>
<tr>
<th>Lease Rental Costs</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Lease Expense on Operating Leases</td>
<td>$368</td>
<td>$364</td>
<td>$340</td>
</tr>
<tr>
<td>Amortization of Capital Leases</td>
<td>97</td>
<td>68</td>
<td>64</td>
</tr>
<tr>
<td>Interest on Capital Leases</td>
<td>16</td>
<td>20</td>
<td>17</td>
</tr>
<tr>
<td><strong>Total Lease Rental Costs</strong></td>
<td>$481</td>
<td>$452</td>
<td>$421</td>
</tr>
</tbody>
</table>

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets. Capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on our Consolidated Balance Sheets.

<table>
<thead>
<tr>
<th>December 31,</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Property, Plant and Equipment Under Capital Leases</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>$70</td>
<td>$89</td>
</tr>
<tr>
<td>Distribution</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Other</td>
<td>443</td>
<td>458</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>-</td>
<td>39</td>
</tr>
<tr>
<td><strong>Total Property, Plant and Equipment Under Capital Leases</strong></td>
<td>528</td>
<td>601</td>
</tr>
<tr>
<td>Accumulated Amortization</td>
<td>205</td>
<td>232</td>
</tr>
<tr>
<td><strong>Net Property, Plant and Equipment Under Capital Leases</strong></td>
<td>$323</td>
<td>$369</td>
</tr>
<tr>
<td><strong>Obligations Under Capital Leases</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noncurrent Liability</td>
<td>$226</td>
<td>$267</td>
</tr>
<tr>
<td>Liability Due Within One Year</td>
<td>99</td>
<td>104</td>
</tr>
<tr>
<td><strong>Total Obligations Under Capital Leases</strong></td>
<td>$325</td>
<td>$371</td>
</tr>
</tbody>
</table>
Future minimum lease payments consisted of the following at December 31, 2008:

<table>
<thead>
<tr>
<th>Future Minimum Lease Payments</th>
<th>Capital Leases</th>
<th>Noncancelable Operating Leases</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$ 94</td>
<td>$ 336</td>
</tr>
<tr>
<td>2010</td>
<td>67</td>
<td>310</td>
</tr>
<tr>
<td>2011</td>
<td>52</td>
<td>461</td>
</tr>
<tr>
<td>2012</td>
<td>26</td>
<td>222</td>
</tr>
<tr>
<td>2013</td>
<td>20</td>
<td>215</td>
</tr>
<tr>
<td>Later Years</td>
<td>149</td>
<td>1,671</td>
</tr>
<tr>
<td>Total Future Minimum Lease Payments</td>
<td>$ 408</td>
<td>$ 3,215</td>
</tr>
<tr>
<td>Less Estimated Interest Element</td>
<td>83</td>
<td></td>
</tr>
<tr>
<td>Estimated Present Value of Future Minimum Lease Payments</td>
<td>$ 325</td>
<td></td>
</tr>
</tbody>
</table>
Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2008 are as follows:

<table>
<thead>
<tr>
<th></th>
<th>AEGCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Future Minimum Lease Payments</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$74</td>
<td>$74</td>
</tr>
<tr>
<td>2010</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>2011</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>2012</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>2013</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>Later Years</td>
<td>665</td>
<td>665</td>
</tr>
<tr>
<td>Total Future Minimum Lease Payments</td>
<td>$1,035</td>
<td>$1,035</td>
</tr>
</tbody>
</table>

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as new operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of December 31, 2008. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M’s maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo’s is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss.

We have other railcar lease arrangements that do not utilize this type of financing structure.

Sabine Dragline Lease

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46R, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a $53 million electric dragline for Sabine’s mining operations. In 2006, the initial capital outlay for the dragline was $26 million. Sabine incurred an additional $14 million and $13 million of transportation, assembly and upgrade costs in 2008 and 2007 respectively. The dragline was completed in August 2008. For the years ended December 31, 2008 and 2007, Sabine paid $1 million and $2 million, respectively, of interim rent prior to the completion in August 2008. Sabine began quarterly principal and interest payments on the outstanding lease obligation in November 2008. The capital lease asset was included in Property, Plant and Equipment – Other and Construction Work in Progress on our December 31, 2008 and 2007 Consolidated Balance Sheets, respectively. The short-term and long-term capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on our December 31, 2008 and 2007 Consolidated Balance Sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.
**I&M Nuclear Fuel Lease**

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M’s Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $57 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Property, Plant and Equipment – Other and the short-term and long-term capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other, respectively, on our December 31, 2008 and 2007 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2008 are as follows, based on estimated fuel burn:

<table>
<thead>
<tr>
<th>Future Minimum Lease Payments</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$ 25</td>
</tr>
<tr>
<td>2010</td>
<td>18</td>
</tr>
<tr>
<td>2011</td>
<td>4</td>
</tr>
<tr>
<td>2012</td>
<td>7</td>
</tr>
<tr>
<td>2013</td>
<td>3</td>
</tr>
<tr>
<td>Later Years</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Future Minimum Lease Payments</strong></td>
<td><strong>$ 57</strong></td>
</tr>
</tbody>
</table>

14. **FINANCING ACTIVITIES**

**Common Stock**

We issued 68 thousand, 2.4 million and 2.3 million shares of common stock in connection with our stock option plan during 2008, 2007 and 2006, respectively.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Shares of Common Stock</th>
<th>Issued</th>
<th>Held in Treasury</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance, January 1, 2006</td>
<td>415,218,830</td>
<td>21,499,992</td>
</tr>
<tr>
<td>Issued</td>
<td>2,955,898</td>
<td>-</td>
</tr>
<tr>
<td>Balance, December 31, 2006</td>
<td>418,174,728</td>
<td>21,499,992</td>
</tr>
<tr>
<td>Issued</td>
<td>3,751,968</td>
<td>-</td>
</tr>
<tr>
<td>Balance, December 31, 2007</td>
<td>421,926,696</td>
<td>21,499,992</td>
</tr>
<tr>
<td>Issued</td>
<td>4,394,552</td>
<td>-</td>
</tr>
<tr>
<td>Treasury Stock Contributed to AEP Foundation</td>
<td>-</td>
<td>(1,250,000)</td>
</tr>
<tr>
<td>Balance, December 31, 2008</td>
<td>426,321,248</td>
<td>20,249,992</td>
</tr>
</tbody>
</table>
Preferred Stock

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

<table>
<thead>
<tr>
<th>Not Subject to Mandatory Redemption:</th>
<th>Call Price Per Share (a)</th>
<th>December 31, 2008 Shares (b)</th>
<th>December 31, 2007 Shares (c)</th>
<th>Amount (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.00% - 5.00%</td>
<td>$102-$110</td>
<td>1,525,903</td>
<td>606,878</td>
<td>$61</td>
</tr>
</tbody>
</table>

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.

(b) As of December 31, 2008 and 2007, our subsidiaries had 14,488,045 shares of $100 par value preferred stock, 22,200,000 shares of $25 par value preferred stock and 7,822,480 shares of no par value preferred stock that were authorized but unissued.

(c) There were no shares of preferred stock redeemed in 2008. The number of shares of preferred stock redeemed was 166 shares in 2007 and 598 shares in 2006.
### Long-term Debt

<table>
<thead>
<tr>
<th>Type of Debt and Maturity</th>
<th>Weighted Average Interest Rate December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Senior Unsecured Notes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008-2011</td>
<td>5.07%</td>
<td>4.3875%-6.60%</td>
<td>$2,065</td>
</tr>
<tr>
<td>2012-2018</td>
<td>5.58%</td>
<td>4.85%-6.375%</td>
<td>$4,548</td>
</tr>
<tr>
<td>2019-2038</td>
<td>6.38%</td>
<td>5.625%-7.00%</td>
<td>$4,456</td>
</tr>
<tr>
<td>Pollution Control Bonds</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008-2011 (c)</td>
<td>5.69%</td>
<td>4.15%-7.125%</td>
<td>$336</td>
</tr>
<tr>
<td>2012-2024 (c)</td>
<td>4.03%</td>
<td>0.75%-6.05%</td>
<td>$775</td>
</tr>
<tr>
<td>2025-2042</td>
<td>5.67%</td>
<td>0.85%-13.00%</td>
<td>$835</td>
</tr>
<tr>
<td>Notes Payable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008-2024</td>
<td>6.66%</td>
<td>4.47%-7.49%</td>
<td>$233</td>
</tr>
<tr>
<td>Securitization Bonds</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008-2020</td>
<td>5.34%</td>
<td>4.98%-6.25%</td>
<td>$2,132</td>
</tr>
<tr>
<td>Junior Subordinated Debentures</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2063</td>
<td>8.75%</td>
<td>8.75%</td>
<td>315</td>
</tr>
<tr>
<td>First Mortgage Bonds</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>-</td>
<td>-</td>
<td>19</td>
</tr>
<tr>
<td>Notes Payable to Trust</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2043</td>
<td>-</td>
<td>-</td>
<td>113</td>
</tr>
<tr>
<td>Spent Nuclear Fuel Obligation</td>
<td></td>
<td></td>
<td>264</td>
</tr>
<tr>
<td>Other Long-term Debt</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011-2026</td>
<td>3.50%</td>
<td>3.20125%-13.718%</td>
<td>88</td>
</tr>
</tbody>
</table>

Unamortized Discount (net) | (64) | (62) |
Total Long-term Debt Outstanding | 15,983 | 14,994 |
Less Portion Due Within One Year | 447 | 792 |
Long-term Portion | $15,536 | $14,202 |

(a) Certain senior unsecured notes have been adjusted for MTM of Fair Value Hedges associated with the debt.
(b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.
(c) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.
(d) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(e) In October 2006, AEP Texas Central Transition Funding II LLC (TFII), a subsidiary of TCC, issued $1.7 billion in securitization bonds with interest rates ranging from 4.98% to 5.3063% and final maturity dates ranging from January 2012 to July 2021. Scheduled final payment dates range from January 2010 to July 2020. TFII is the sole owner of the transition charges and the original transition property. The holders of the securitization bonds do not have recourse to any assets or revenues of TCC. The creditors of TCC do not have recourse to any assets or revenues of TFII, including, without limitation, the original transition property.
(f) The net proceeds from the sale of junior subordinated debentures were used for general corporate purposes including the payment of short-term indebtedness.
(g) In May 2004, cash and treasury securities were deposited with a trustee to defease all of TCC’s outstanding first mortgage bonds. The defeased TCC first mortgage bonds had a balance of $19 million in 2007. The defeased TCC first mortgage bonds were retired in February 2008. Trust fund assets related to this obligation of $22 million are included in Other Temporary Investments on our Consolidated Balance Sheets at December 31, 2007.
(h) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 9).
(i) Other long-term debt in 2007 and 2008 consists of a financing obligation under a sale and leaseback agreement. In 2008, AEGCo issued an $85 million 3-year credit facility to be used for working capital and other general corporate purposes.
LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2008 IS PAYABLE AS FOLLOWS:

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>After</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principal Amount</td>
<td>$447</td>
<td>$1,851</td>
<td>$809</td>
<td>$1,297</td>
<td>$11,042</td>
<td></td>
<td>$16,047</td>
</tr>
<tr>
<td>Unamortized Discount</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$(64)</td>
</tr>
<tr>
<td><strong>Total Long-term Debt Outstanding at December 31, 2008</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>$15,983</strong></td>
</tr>
</tbody>
</table>

In January 2009, I&M issued $475 million of 7.00% Senior Unsecured Notes due in 2019.

In January 2009, TCC retired $50 million of 4.98% and $31 million of 5.56% Securitization Bonds due in 2010.

In February 2009, PSO reissued $34 million of 5.25% Pollution Control Bonds due in 2014.

In the first quarter of 2008, bond insurers’ exposure in connection with developments in the subprime credit market resulted in increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates. Consequently, we chose to exit the auction-rate debt market and reduced our outstanding auction-rate securities from the December 2007 balance by $1.2 billion. As of December 31, 2008, $272 million of our auction-rate tax-exempt long-term debt, with rates ranging between 2.034% and 13%, remained outstanding with rates reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. As of December 31, 2008, $367 million of the prior auction-rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 0.85% to 1.52%, $495 million was issued at fixed rates ranging from 4.5% to 5.625% and trustees held, on our behalf, approximately $330 million of our reacquired auction-rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

As of December 31, 2008, approximately $218 million of the $272 million of outstanding auction-rate debt relates to a lease structure with JMG that we are unable to refinance without their consent. The rates for this debt range from 6.388% to 13%. The initial term for the JMG lease structure matures on March 31, 2010. We are evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO.

**Dividend Restrictions**

Under the Federal Power Act, AEP’s public utility subsidiaries are restricted from paying dividends out of stated capital.

**Trust Preferred Securities**

SWEPCo had a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46R. The SWEPCo trust, which held mandatorily redeemable trust preferred securities, is reported as two components on our Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2007, is included in Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2007, are reported as Notes Payable to Trust within Long-term Debt. Both the investment in the trust and the Junior Subordinated Debentures were retired in 2008.
Lines of Credit and Short-term Debt

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2008, we had credit facilities totaling $3 billion to support our commercial paper program (see “Credit Facilities” section below). For the corporate borrowing program, the maximum amount of commercial paper outstanding during 2008 was $1.2 billion and the weighted average interest rate of commercial paper outstanding during the year was 3.32%. No commercial paper was outstanding at December 31, 2008 due to market conditions. In 2008, we borrowed $2 billion under these credit facilities. Our outstanding short-term debt was as follows:

<table>
<thead>
<tr>
<th>Type of Debt</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Outstanding Amount (in thousands)</td>
<td>Interest Rate (a)</td>
</tr>
<tr>
<td>Commercial Paper – AEP</td>
<td>$ -</td>
<td>-</td>
</tr>
<tr>
<td>Commercial Paper – JMG (b)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Line of Credit – Sabine Mining Company (c)</td>
<td>7,172</td>
<td>1.54%</td>
</tr>
<tr>
<td>Lines of Credit – AEP</td>
<td>1,969,000</td>
<td>2.28% (d)</td>
</tr>
<tr>
<td>Total</td>
<td>$ 1,976,172</td>
<td>2.28% (d)</td>
</tr>
</tbody>
</table>

(a) Weighted average rate.
(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce available liquidity under AEP’s credit facilities.
(c) Sabine Mining Company is consolidated under FIN 46R. This line of credit does not reduce available liquidity under AEP’s credit facilities.
(d) Rate based on LIBOR.

Credit Facilities

As of December 31, 2008, in support of our commercial paper program, we had two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $46 million following its bankruptcy. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, we may issue letters of credit. As of December 31, 2008, $372 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,” allowing the receivables to be taken off of AEP Credit’s balance sheet and our Consolidated Balance Sheet and allowing AEP Credit to repay any debt obligations to the affiliated utility subsidiaries. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies’ receivables, and accelerate AEP Credit’s cash collections.
In October 2008, we renewed AEP Credit’s sale of receivables agreement. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009. We intend to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in October 2008 and was extended until October 2009, provided a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the previous sale of receivable agreement, the commitment increased to $700 million for the months of August and September to accommodate seasonal demand. At December 31, 2008, $650 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo’s accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td>($ in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proceeds from Sale of Accounts Receivable</td>
<td>$7,717</td>
<td>$6,970</td>
</tr>
<tr>
<td>Loss on Sale of Accounts Receivable</td>
<td>20</td>
<td>33</td>
</tr>
<tr>
<td>Average Variable Discount Rate</td>
<td>3.19%</td>
<td>5.39%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts Receivable Retained Interest and Pledged as Collateral</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Less Uncollectible Accounts</td>
<td>$118</td>
<td>$71</td>
</tr>
<tr>
<td>Deferred Revenue from Servicing Accounts Receivable</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Retained Interest if 10% Adverse Change in Uncollectible Accounts</td>
<td>116</td>
<td>68</td>
</tr>
<tr>
<td>Retained Interest if 20% Adverse Change in Uncollectible Accounts</td>
<td>114</td>
<td>66</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td>(in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customer Accounts Receivable Retained</td>
<td>$569</td>
<td>$730</td>
</tr>
<tr>
<td>Accrued Unbilled Revenues Retained</td>
<td>449</td>
<td>379</td>
</tr>
<tr>
<td>Miscellaneous Accounts Receivable Retained</td>
<td>90</td>
<td>60</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts Retained</td>
<td>(42)</td>
<td>(52)</td>
</tr>
<tr>
<td>Total Net Balance Sheet Accounts Receivable</td>
<td>1,066</td>
<td>1,117</td>
</tr>
<tr>
<td>Customer Accounts Receivable Securitized</td>
<td>650</td>
<td>507</td>
</tr>
<tr>
<td>Total Accounts Receivable Managed</td>
<td>$1,716</td>
<td>$1,624</td>
</tr>
</tbody>
</table>

| Net Uncollectible Accounts Written Off | $37   | $24   |

Customer accounts receivable retained and securitized for the electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $22 million and $30 million at December 31, 2008 and 2007, respectively. AEP Credit’s delinquent customer accounts receivable represents accounts greater than 30 days past due.
As previously approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 9,000,000 shares may be used under this plan for full value share awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders last approved the LTIP in 2005. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

We adopted SFAS 123 (revised 2004) “Share-Based Payments” (SFAS 123R), effective January 1, 2006.

Stock Options

We did not grant stock options in 2008, 2007 or 2006 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP’s common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant’s continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

<table>
<thead>
<tr>
<th>Stock Options</th>
<th>Years Ended December 31,</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2008</td>
<td>2007</td>
<td>2006</td>
</tr>
<tr>
<td>Fair Value of Stock Options Vested</td>
<td>$25</td>
<td>$1,377</td>
<td>$3,667</td>
<td></td>
</tr>
<tr>
<td>Intrinsic Value of Options Exercised (a)</td>
<td>655</td>
<td>29,389</td>
<td>16,823</td>
<td></td>
</tr>
</tbody>
</table>

(a) Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2008, 2007 and 2006 is as follows:

<table>
<thead>
<tr>
<th>Options</th>
<th>Weighted Average Exercise Price</th>
<th>Options</th>
<th>Weighted Average Exercise Price</th>
<th>Options</th>
<th>Weighted Average Exercise Price</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td>(in thousands)</td>
<td></td>
<td>(in thousands)</td>
</tr>
<tr>
<td>Outstanding at January 1,</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Granted</td>
<td>-</td>
<td>N/A</td>
<td>Exercised/Converted</td>
<td>-</td>
<td>N/A</td>
</tr>
<tr>
<td>Forfeited/Expired</td>
<td>(68)</td>
<td>31.97</td>
<td>Forfeited/Expired</td>
<td>-</td>
<td>N/A</td>
</tr>
<tr>
<td>Outstanding at December 31,</td>
<td>1,128</td>
<td>32.73</td>
<td>1,196</td>
<td>32.69</td>
<td>3,670</td>
</tr>
<tr>
<td>Options Exercisable at December 31,</td>
<td>1,125</td>
<td>32.72</td>
<td>1,193</td>
<td>32.68</td>
<td>3,411</td>
</tr>
</tbody>
</table>
The following table summarizes information about AEP stock options outstanding at December 31, 2008.

### Options Outstanding

<table>
<thead>
<tr>
<th>2008 Range of Exercise Prices</th>
<th>Number of Options Outstanding (in thousands)</th>
<th>Weighted Average Remaining Life (in years)</th>
<th>Weighted Average Exercise Price</th>
<th>Aggregate Intrinsic Value (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$27.06 - $27.95</td>
<td>509</td>
<td>4.02</td>
<td>$27.39</td>
<td>$3,001</td>
</tr>
<tr>
<td>$30.76 - $38.65</td>
<td>472</td>
<td>2.83</td>
<td>34.15</td>
<td>375</td>
</tr>
<tr>
<td>$44.10 - $49.00</td>
<td>147</td>
<td>2.36</td>
<td>46.71</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total (a)</strong></td>
<td><strong>1,128</strong></td>
<td><strong>3.31</strong></td>
<td><strong>32.73</strong></td>
<td><strong>$3,376</strong></td>
</tr>
</tbody>
</table>

(a) Options outstanding are not significantly different from the number of shares expected to vest.

The following table summarizes information about AEP stock options exercisable at December 31, 2008.

### Options Exercisable

<table>
<thead>
<tr>
<th>2008 Range of Exercise Prices</th>
<th>Number of Options Exercisable (in thousands)</th>
<th>Weighted Average Remaining Life (in years)</th>
<th>Weighted Average Exercise Price</th>
<th>Aggregate Intrinsic Value (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$27.06 - $27.95</td>
<td>509</td>
<td>4.02</td>
<td>$27.39</td>
<td>$3,001</td>
</tr>
<tr>
<td>$30.76 - $38.65</td>
<td>469</td>
<td>2.81</td>
<td>34.12</td>
<td>375</td>
</tr>
<tr>
<td>$44.10 - $49.00</td>
<td>147</td>
<td>2.36</td>
<td>46.71</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,125</strong></td>
<td><strong>3.30</strong></td>
<td><strong>32.72</strong></td>
<td><strong>$3,376</strong></td>
</tr>
</tbody>
</table>

We include the proceeds received from exercised stock options in common stock and paid-in capital.

### Performance Units

Our performance units are equal in value to the market value of shares of AEP common stock. The number of performance units held is multiplied by a performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. Performance units are paid in cash or stock at the employee’s election at the end of a three-year performance and vesting period, unless they are needed to satisfy a participant’s stock ownership requirement. In that case, they are mandatorily deferred as AEP Career Shares, a form of phantom stock units, until after the end of the participant’s AEP career. AEP Career Shares have a value equivalent to the market value of shares of AEP common stock shares and are paid in cash after the participant’s termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.
The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2008, 2007 and 2006 as follows:

<table>
<thead>
<tr>
<th>Performance Units</th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>Awarded Units (in thousands)</td>
<td>1,384</td>
</tr>
<tr>
<td>Weighted Average Unit Fair Value at Grant Date</td>
<td>$ 30.11</td>
</tr>
<tr>
<td>Vesting Period (years)</td>
<td>3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Performance Units and AEP Career Shares (Reinvested Dividends Portion)</th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>Awarded Units (in thousands)</td>
<td>149</td>
</tr>
<tr>
<td>Weighted Average Grant Date Fair Value</td>
<td>$ 37.21</td>
</tr>
<tr>
<td>Vesting Period (years)</td>
<td>(a)</td>
</tr>
</tbody>
</table>

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: three-year total shareholder return measured relative to utility companies in the S&P 500 Index and three-year cumulative earnings per share measured relative to a board-approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 days of the performance period.

In January 2009, the HR Committee certified a performance score for the three-year period ended December 31, 2008 of 120.3%. As a result, 1,088,302 performance units were earned. Of this amount 42,214 were mandatorily deferred as AEP Career Shares, 66,415 were voluntarily deferred into the Incentive Compensation Deferral Program and the remaining units were paid in cash.

In January 2008, the HR Committee certified a performance score for the three-year period ended December 31, 2007 of 154.3%. As a result, 1,508,383 performance units were earned. Of this amount 313,781 were mandatorily deferred as AEP Career Shares, 68,107 were voluntarily deferred into the Incentive Compensation Deferral Program and the remaining units were paid in cash.

Due to the anticipated 2004 CEO succession, on December 10, 2003, the HR Committee made performance unit grants for the shortened performance period of December 10, 2003 through December 31, 2004. No performance period ended on December 31, 2006 because this performance period was shorter than the normal three-year period and there were no other performance unit grants in 2003. In 2005, the HR Committee certified a performance factor of 123.1% for performance units granted on December 10, 2003 and 946,789 performance units were mandatorily deferred into AEP stock units. These units had a three year vesting period which ended on December 31, 2006, at which time, 917,032 units vested and the remaining units were forfeited due to participant terminations. Of the 917,032 vested units 388,801 were mandatorily deferred as AEP Career Shares and the remaining units were paid in cash.

The cash payouts for the years ended December 31, 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>(in thousands)</td>
</tr>
<tr>
<td>Cash Payouts for Performance Units</td>
</tr>
<tr>
<td>Cash Payouts for AEP Career Share Distributions</td>
</tr>
</tbody>
</table>
Restricted Shares and Restricted Stock Units

The independent members of the Board of Directors granted 300,000 restricted shares to the Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005 and 50,000 vested on January 1, 2006. The remaining 200,000 restricted shares vest, subject to his continued employment, in approximately equal thirds on November 30, 2009, 2010 and 2011. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market price of $30.76. The maximum term for these restricted shares is eight years. AEP has not granted other restricted shares. Dividends on these restricted shares are paid in cash.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant’s continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on RSUs accrue as additional RSUs and vest on the last vesting date associated with the underlying units. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market price. The maximum contractual term of RSUs is six years from the grant date.

The HR Committee has granted RSUs with performance vesting conditions to certain employees who are integral to our project to design and build proposed IGCC power plants. In February 2007, the HR Committee granted approximately 12,000 shares of RSUs that vest 10% on each of the first three anniversaries of the grant date. An additional 10% vest on the date the IGCC plant achieves substantial completion. Another 20% vest on the date the IGCC plant achieves commercial operation. An additional 20% vest one year after the IGCC plant achieves commercial operation, subject to achievement of plant availability targets. The remaining 20% vest two years after the IGCC plant achieves commercial operation, subject to achievement of plant availability targets.

In January 2006, the HR Committee granted approximately 11,000 shares of RSUs with performance vesting conditions related to our IGCC project. Twenty percent of these awards vested on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operation. The remaining 20% vest one year after the IGCC plant achieves commercial operation, subject to achievement of plant availability targets.

In 2008, the HR Committee did not grant RSUs with performance vesting conditions.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2008, 2007 and 2006 as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Restricted Stock Units</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Awarded Units (in thousands)</td>
<td>56</td>
<td>148</td>
<td>65</td>
</tr>
<tr>
<td>Weighted Average Grant Date Fair Value</td>
<td>$41.69</td>
<td>$45.89</td>
<td>$37.47</td>
</tr>
</tbody>
</table>

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Restricted Shares and Restricted Stock Units</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fair Value of Restricted Shares and Restricted Stock Units Vested</td>
<td>$2,619</td>
<td>$2,711</td>
<td>$3,939</td>
</tr>
<tr>
<td>Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)</td>
<td>2,534</td>
<td>3,646</td>
<td>4,686</td>
</tr>
</tbody>
</table>

(a) Intrinsic value is calculated as market price.
A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2008 and changes during the year ended December 31, 2008 are as follows:

<table>
<thead>
<tr>
<th>Nonvested Restricted Shares and Restricted Stock Units</th>
<th>Shares/Units</th>
<th>Weighted Average Grant Date Fair Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nonvested at January 1, 2008</td>
<td>453</td>
<td>$36.93</td>
</tr>
<tr>
<td>Granted</td>
<td>56</td>
<td>$41.69</td>
</tr>
<tr>
<td>Vested</td>
<td>(65)</td>
<td>$40.19</td>
</tr>
<tr>
<td>Forfeited</td>
<td>(1)</td>
<td>$42.80</td>
</tr>
<tr>
<td>Nonvested at December 31, 2008</td>
<td>443</td>
<td>$37.04</td>
</tr>
</tbody>
</table>

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2008 was $14 million and the weighted average remaining contractual life was 2.62 years.

**Other Stock-Based Plans**

We also have a Stock Unit Accumulation Plan for Nonemployee Directors providing each nonemployee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The nonemployee directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2008, 2007 and 2006.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2008, 2007 and 2006 as follows:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Awarded Units (in thousands)</td>
<td>43</td>
<td>28</td>
<td>33</td>
</tr>
<tr>
<td>Weighted Average Grant Date Fair Value</td>
<td>$37.72</td>
<td>$46.46</td>
<td>$36.66</td>
</tr>
</tbody>
</table>

**Share-based Compensation Plans**

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Compensation Cost for Share-based Payment Arrangements (a)</td>
<td>$(18,028)</td>
<td>$72,004</td>
<td>$45,842</td>
</tr>
<tr>
<td>Actual Tax Benefit Realized</td>
<td>(6,310)</td>
<td>25,201</td>
<td>16,045</td>
</tr>
<tr>
<td>Total Compensation Cost Capitalized</td>
<td>(5,026)</td>
<td>18,077</td>
<td>10,953</td>
</tr>
</tbody>
</table>

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance on our Consolidated Statements of Income.

(b) In 2008, AEP’s declining total shareholder return and lower stock price significantly reduced the accruals for performance units.
During the years ended December 31, 2008, 2007 and 2006, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2008, there was $70 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.78 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash Received from Stock Options Exercised</td>
<td>$ 2,170</td>
<td>$ 86,527</td>
<td>$ 77,534</td>
</tr>
<tr>
<td>Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised</td>
<td>219</td>
<td>10,282</td>
<td>5,825</td>
</tr>
</tbody>
</table>

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we could use reacquired shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset AEP’s tax withholding obligation.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

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

<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>Regulated</th>
<th>Nonregulated</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Property, Plant and Equipment</td>
<td>Annual Composite Depreciation Rate Ranges</td>
</tr>
<tr>
<td>Production</td>
<td>$ 11,650</td>
<td>$ 5,922</td>
</tr>
<tr>
<td>Transmission</td>
<td>7,938</td>
<td>2,371</td>
</tr>
<tr>
<td>Distribution</td>
<td>12,816</td>
<td>3,191</td>
</tr>
<tr>
<td>CWIP</td>
<td>2,770</td>
<td>(59)</td>
</tr>
<tr>
<td>Other</td>
<td>2,705</td>
<td>1,265</td>
</tr>
<tr>
<td>Total</td>
<td>$ 37,879</td>
<td>$ 12,690</td>
</tr>
</tbody>
</table>
We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Prior to 2008, the lignite mine of DHLC was scheduled to be shut down in May 2011. In December 2007, the LPSC unanimously voted to extend the life of the lignite mine of DHLC through 2016. In December 2008, we received the final order. The average amortization rate for coal rights and mine development costs was $0.26 per ton in 2008 and $0.66 per ton in 2007 and 2006.

For cost-based rate-regulated operations, the composite deprecation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

### Asset Retirement Obligations (ARO)

We record ARO in accordance with SFAS 143 “Accounting for Asset Retirement Obligations” and FIN 47 “Accounting for Conditional Asset Retirement Obligations” for our legal obligations for asbestos removal and for the retirement of certain ash ponds, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property’s use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.
The following is a reconciliation of the 2008 and 2007 aggregate carrying amounts of ARO:

<table>
<thead>
<tr>
<th>Carrying Amount of ARO (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ARO at December 31, 2006</td>
</tr>
<tr>
<td>Accretion Expense</td>
</tr>
<tr>
<td>Liabilities Incurred</td>
</tr>
<tr>
<td>Liabilities Settled</td>
</tr>
<tr>
<td>Revisions in Cash Flow Estimates</td>
</tr>
<tr>
<td>ARO at December 31, 2006 (a)</td>
</tr>
<tr>
<td>Accretion Expense</td>
</tr>
<tr>
<td>Liabilities Incurred</td>
</tr>
<tr>
<td>Liabilities Settled</td>
</tr>
<tr>
<td>Revisions in Cash Flow Estimates</td>
</tr>
<tr>
<td>ARO at December 31, 2008 (b)</td>
</tr>
</tbody>
</table>

(a) The current portion of our ARO, totaling $3 million, is included in Other in the Current Liabilities section of our 2007 Consolidated Balance Sheet.

(b) The current portion of our ARO, totaling $4 million, is included in Other in the Current Liabilities section of our 2008 Consolidated Balance Sheet.

As of December 31, 2008 and 2007, our ARO liability was $1.2 billion and $1.1 billion, respectively, and included $891 million and $846 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2008 and 2007, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1 billion and $1.1 billion, respectively, relating to the Cook Plant and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

**Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization**

Our amounts of allowance for borrowed and equity funds used during construction is summarized in the following table:

<table>
<thead>
<tr>
<th></th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>$45</td>
</tr>
<tr>
<td>Allowance for Borrowed Funds Used During Construction</td>
<td>75</td>
</tr>
</tbody>
</table>
Jointly-owned Electric Utility Plants

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

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Percent of Ownership</th>
<th>Utility Plant in Service</th>
<th>Construction Work in Progress (i)</th>
<th>Accumulated Depreciation</th>
</tr>
</thead>
<tbody>
<tr>
<td>W.C. Beckjord Generating Station (Unit No. 6) (a)</td>
<td>Coal 12.5%</td>
<td>$18</td>
<td>$2</td>
<td>$8</td>
</tr>
<tr>
<td>Conesville Generating Station (Unit No. 4) (b)</td>
<td>Coal 43.5%</td>
<td>86</td>
<td>173</td>
<td>51</td>
</tr>
<tr>
<td>J.M. Stuart Generating Station (c)</td>
<td>Coal 26.0%</td>
<td>478</td>
<td>24</td>
<td>144</td>
</tr>
<tr>
<td>Wm. H. Zimmer Generating Station (a)</td>
<td>Coal 25.4%</td>
<td>762</td>
<td>4</td>
<td>344</td>
</tr>
<tr>
<td>Dolet Hills Generating Station (Unit No. 1) (d)</td>
<td>Lignite 40.2%</td>
<td>255</td>
<td>1</td>
<td>182</td>
</tr>
<tr>
<td>Flint Creek Generating Station (Unit No. 1) (e)</td>
<td>Coal 50.0%</td>
<td>103</td>
<td>10</td>
<td>62</td>
</tr>
<tr>
<td>Pirkey Generating Station (Unit No. 1) (e)</td>
<td>Lignite 85.9%</td>
<td>491</td>
<td>8</td>
<td>336</td>
</tr>
<tr>
<td>Oklaunion Generating Station (Unit No. 1) (f)</td>
<td>Coal 70.3%</td>
<td>383</td>
<td>7</td>
<td>192</td>
</tr>
<tr>
<td>Turk Generating Plant (g)</td>
<td>Coal 73.33%</td>
<td>-</td>
<td>510</td>
<td>-</td>
</tr>
<tr>
<td>Transmission</td>
<td>N/A (h)</td>
<td>70</td>
<td>-</td>
<td>46</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Company’s Share at December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Type</td>
</tr>
<tr>
<td>-----------------</td>
</tr>
<tr>
<td>W.C. Beckjord Generating Station (Unit No. 6) (a)</td>
</tr>
<tr>
<td>Conesville Generating Station (Unit No. 4) (b)</td>
</tr>
<tr>
<td>J.M. Stuart Generating Station (c)</td>
</tr>
<tr>
<td>Wm. H. Zimmer Generating Station (a)</td>
</tr>
<tr>
<td>Dolet Hills Generating Station (Unit No. 1) (d)</td>
</tr>
<tr>
<td>Flint Creek Generating Station (Unit No. 1) (e)</td>
</tr>
<tr>
<td>Pirkey Generating Station (Unit No. 1) (e)</td>
</tr>
<tr>
<td>Oklaunion Generating Station (Unit No. 1) (f)</td>
</tr>
<tr>
<td>Turk Generating Plant (g)</td>
</tr>
<tr>
<td>Transmission</td>
</tr>
</tbody>
</table>

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by Cleco Corporation, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2008, construction costs totaling $34.8 million have been billed to the other owners.
(h) Varying percentages of ownership.
(i) Primarily relates to construction of Turk Generating Plant and environmental upgrades including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable
17. **UNAUDITED QUARTERLY FINANCIAL INFORMATION**

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our net income for interim periods. Quarterly results are not necessarily indicative of a full year’s operations because of various factors. Our unaudited quarterly financial information is as follows:

<table>
<thead>
<tr>
<th></th>
<th>March 31</th>
<th>2008 Quarterly Periods Ended</th>
<th>December 31</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions – except per share amounts)</td>
<td>June 30</td>
<td>September 30</td>
</tr>
<tr>
<td>Revenues</td>
<td>$ 3,467</td>
<td>$ 3,546</td>
<td>$ 4,191</td>
</tr>
<tr>
<td>Operating Income</td>
<td>1,043 (a)(b)</td>
<td>586</td>
<td>737</td>
</tr>
<tr>
<td>Income Before Discontinued Operations and Extraordinary Loss</td>
<td>573 (a)(b)</td>
<td>280</td>
<td>374</td>
</tr>
<tr>
<td>Discontinued Operations, Net of Tax</td>
<td>-</td>
<td>1</td>
<td>-</td>
</tr>
<tr>
<td>Net Income</td>
<td>573 (a)(b)</td>
<td>281</td>
<td>374</td>
</tr>
</tbody>
</table>

Basic Earnings per Share:
- Earnings per Share Before Discontinued Operations and Extraordinary Loss:
  - 1.43 | 0.70 | 0.93 | 0.34 |
- Discontinued Operations per Share:
  - - | - | - | 0.03 |
- Earnings per Share:
  - 1.43 | 0.70 | 0.93 | 0.37 |

Diluted Earnings per Share:
- Earnings per Share Before Discontinued Operations and Extraordinary Loss (d):
  - 1.43 | 0.70 | 0.93 | 0.34 |
- Discontinued Operations per Share:
  - - | - | - | 0.03 |
- Earnings per Share (e):
  - 1.43 | 0.70 | 0.93 | 0.37 |

(a) See “TEM Litigation” section of Note 6 for discussion of the settlement reached with TEM in January 2008.
(b) See “Oklahoma 2007 Ice Storms” section of Note 4 for discussion of the first quarter 2008 reversal of expenses incurred from ice storms in January and December 2007.
(c) See “Allocation of Off-system Sales Margins” section of Note 4 for discussion of the financial statement impact of the FERC’s November 2008 order related to the SIA.
(d) Amounts for 2008 do not add to $3.39 for Diluted Earnings per Share Before Discontinued Operations and Extraordinary Loss due to rounding.
(e) Amounts for 2008 do not add to $3.42 for Diluted Earnings per Share due to rounding.
<table>
<thead>
<tr>
<th></th>
<th>March 31</th>
<th>2007 Quarterly Periods Ended</th>
<th>December 31</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>June 30</td>
<td>September 30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$ 3,146</td>
<td>$ 3,789</td>
</tr>
<tr>
<td>Revenues</td>
<td>$ 3,169</td>
<td>$ 3,146</td>
<td>$ 3,789</td>
</tr>
<tr>
<td>Operating Income</td>
<td>545 (f)</td>
<td>549</td>
<td>798</td>
</tr>
<tr>
<td>Income Before Discontinued Operations and Extraordinary Loss</td>
<td>271 (f)</td>
<td>257</td>
<td>407</td>
</tr>
<tr>
<td>Discontinued Operations, Net of Tax</td>
<td>-</td>
<td>2</td>
<td>-</td>
</tr>
<tr>
<td>Income Before Extraordinary Loss</td>
<td>271 (f)</td>
<td>259</td>
<td>407</td>
</tr>
<tr>
<td>Extraordinary Loss, Net of Tax</td>
<td>-</td>
<td>(79)(g)</td>
<td>-</td>
</tr>
<tr>
<td>Net Income</td>
<td>271 (f)</td>
<td>180</td>
<td>407</td>
</tr>
</tbody>
</table>

Basic Earnings (Loss) per Share:
- Earnings per Share Before Discontinued Operations and Extraordinary Loss (h) 0.68 0.64 1.02 0.52
- Discontinued Operations per Share (i) - 0.01 - 0.06
- Earnings per Share Before Extraordinary Loss 0.68 0.65 1.02 0.58
- Extraordinary Loss per Share - (0.20) - -
- Earnings per Share 0.68 0.45 1.02 0.58

Diluted Earnings (Loss) per Share:
- Earnings per Share Before Discontinued Operations and Extraordinary Loss 0.68 0.64 1.02 0.52
- Discontinued Operations per Share - 0.01 - 0.05
- Earnings per Share Before Extraordinary Loss 0.68 0.65 1.02 0.57
- Extraordinary Loss per Share - (0.20) - -
- Earnings per Share 0.68 0.45 1.02 0.57

(f) See “Oklahoma 2007 Ice Storms” section of Note 4 for discussion of expenses incurred from ice storms in January and December 2007.
(g) See “Virginia Restructuring” in “Extraordinary Item” section of Note 2 for discussion of the extraordinary loss recorded in the second quarter of 2007.
(h) Amounts for 2007 do not add to $2.87 for Basic Earnings per Share Before Discontinued Operations and Extraordinary Loss due to rounding.
(i) Amounts for 2007 do not add to $0.06 for Basic Earnings per Share for Discontinued Operations due to rounding.
APPALACHIAN POWER COMPANY
AND SUBSIDIARIES
### APPALACHIAN POWER COMPANY AND SUBSIDIARIES
### SELECTED CONSOLIDATED FINANCIAL DATA
### (in thousands)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenues</td>
<td>$2,889,156</td>
<td>$2,607,269</td>
<td>$2,394,028</td>
<td>$2,176,273</td>
<td>$1,957,846</td>
</tr>
<tr>
<td>Operating Income</td>
<td>$312,976</td>
<td>$320,826</td>
<td>$365,643</td>
<td>$283,388</td>
<td>$328,561</td>
</tr>
<tr>
<td>Income Before Extraordinary Loss and Cumulative Effect of Accounting Changes</td>
<td>$122,863</td>
<td>$133,499</td>
<td>$181,449</td>
<td>$135,832</td>
<td>$153,115</td>
</tr>
<tr>
<td>Extraordinary Loss, Net of Tax</td>
<td>-</td>
<td>(78,763)(a)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cumulative Effect of Accounting Changes, Net of Tax</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(2,256)</td>
<td>-</td>
</tr>
<tr>
<td>Net Income</td>
<td>$122,863</td>
<td>$54,736</td>
<td>$181,449</td>
<td>$133,576</td>
<td>$153,115</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Balance Sheets Data</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Property, Plant and Equipment</td>
<td>$9,427,921</td>
<td>$8,738,446</td>
<td>$8,000,278</td>
<td>$7,176,961</td>
<td>$6,563,207</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>$2,675,784</td>
<td>$2,591,833</td>
<td>$2,476,290</td>
<td>$2,524,855</td>
<td>$2,456,417</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>$6,752,137</td>
<td>$6,146,613</td>
<td>$5,523,988</td>
<td>$4,652,106</td>
<td>$4,106,790</td>
</tr>
<tr>
<td>Total Assets</td>
<td>$8,762,664</td>
<td>$7,621,684 (b)</td>
<td>$7,001,798 (b)</td>
<td>$6,201,600 (b)</td>
<td>$5,229,742 (b)</td>
</tr>
<tr>
<td>Common Shareholder’s Equity</td>
<td>$2,376,591</td>
<td>$2,082,032</td>
<td>$2,036,174</td>
<td>$1,803,701</td>
<td>$1,409,718</td>
</tr>
<tr>
<td>Long-term Debt (c)</td>
<td>$3,174,512</td>
<td>$2,847,299</td>
<td>$2,598,664</td>
<td>$2,151,378</td>
<td>$1,784,598</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>$17,752</td>
<td>$17,752</td>
<td>$17,763</td>
<td>$17,784</td>
<td>$17,784</td>
</tr>
<tr>
<td>Obligations Under Capital Leases (c)</td>
<td>$9,313</td>
<td>$11,101</td>
<td>$11,859</td>
<td>$14,892</td>
<td>$19,878</td>
</tr>
</tbody>
</table>

(a) Reflects a change in Virginia law that made SFAS 71 applicable to generation assets. See “Virginia Restructuring” in “Extraordinary Item” section of Note 2.
(b) Includes reclassification of assets due to FSP FIN 39-1 adoption effective in 2008. See “FSP FIN 39-1” section of Note 2.
(c) Includes portion due within one year.
As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 962,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo consolidates Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, its wholly-owned subsidiaries. As a member of the AEP Power Pool, APCo shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. APCo also sells power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member’s prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member’s percentage share of revenues and costs.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies’ and AEP West companies’ allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, 2006 net income and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on APCo’s behalf. APCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. APCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

APCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.
Results of Operations
2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008
Income Before Extraordinary Loss
(in millions)

<table>
<thead>
<tr>
<th>Year Ended December 31, 2007</th>
<th>$133</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Changes in Gross Margin:</strong></td>
<td></td>
</tr>
<tr>
<td>Retail Margins</td>
<td>55</td>
</tr>
<tr>
<td>Off-system Sales</td>
<td>(9)</td>
</tr>
<tr>
<td>Transmission Revenues</td>
<td>2</td>
</tr>
<tr>
<td>Other</td>
<td>(3)</td>
</tr>
<tr>
<td><strong>Total Change in Gross Margin</strong></td>
<td>45</td>
</tr>
<tr>
<td><strong>Changes in Operating Expenses and Other:</strong></td>
<td></td>
</tr>
<tr>
<td>Other Operation and Maintenance</td>
<td>16</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>(59)</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>(10)</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>18</td>
</tr>
<tr>
<td>Other Income</td>
<td>6</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(44)</td>
</tr>
<tr>
<td><strong>Total Change in Operating Expenses and Other</strong></td>
<td>(73)</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>18</td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td>$123</td>
</tr>
</tbody>
</table>

Income Before Extraordinary Loss decreased $10 million to $123 million in 2008. The key drivers of the decrease were a $73 million increase in Operating Expenses and Other, partially offset by an increase in Gross Margin of $45 million and a decrease in Income Tax Expense of $18 million.

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

- Retail Margins increased $55 million primarily due to the following:
  - A $99 million increase due to a provision for rate refund recorded in 2007.
  - A $52 million increase in the recovery of E&R costs in Virginia and construction financing costs in West Virginia.
  - An $18 million increase due to the impact of the Virginia base rate order issued in October 2008.
  - An $8 million increase in FERC formula rates.
  These increases were partially offset by:
  - A $53 million decrease due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $51 million increase in sharing of off-system sales margins with customers due to a full year of sharing in Virginia in 2008 compared to one quarter of sharing in 2007.
  - A $25 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
- Margins from Off-system Sales decreased $9 million primarily due to lower trading margins, partially offset by increased physical sales margins driven by higher prices.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance expenses decreased $16 million primarily due to the following:**
  - A $26 million decrease resulting from a settlement agreement in the third quarter of 2007 related to alleged violations of the NSR provisions of the CAA. The $26 million represents APCo’s allocation of the settlement. See “Federal EPA Complaint and Notice of Violation” section of Note 6.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter 2008 for Virginia’s share of previously expended NSR settlement costs. See “Virginia E&R Costs Recovery Filing” section of Note 4.
  - A $9 million decrease resulting from steam maintenance expenses resulting primarily from forced and planned outages at the Amos Plant in 2007.

  These decreases were partially offset by:
  - A $21 million increase in distribution expenses resulting from an increase in reliability spending and repairs from storm damage in 2008.

- **Depreciation and Amortization expenses increased $59 million primarily due to the following:**
  - A $27 million increase in amortization of carrying charges and depreciation expense that are being collected through the Virginia E&R surcharges.
  - A $22 million favorable adjustment made in the second quarter 2007 for APCo’s Virginia base rate order.
  - A $9 million increase in depreciation expense due to a greater depreciation base resulting from distribution asset improvements.

- **Taxes Other Than Income Taxes increased $10 million primarily due to an unfavorable franchise tax return adjustment recorded in 2008 and an increase in property and payroll taxes in 2008.**

- **Carrying Costs Income increased $18 million primarily due to carrying costs associated with the Virginia E&R case.**

- **Other Income increased $6 million primarily due to higher interest income related to a tax refund in 2008 and other tax adjustments.**

- **Interest Expense increased $44 million primarily due to the following:**
  - A $32 million increase in interest expense resulting from long-term debt issuances in 2008.
  - Interest expense of $24 million related to the December 2008 provision for refund on off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.

  These increases were partially offset by:
  - A $7 million decrease in other interest expense primarily related to interest on the Virginia provision for refund recorded in the second quarter of 2007.
  - A $2 million increase in the debt component of AFUDC resulting from adjustments made in the second quarter of 2007 for the reapplication of SFAS 71.

- **Income Tax Expense decreased $18 million primarily due to a decrease in pretax book income and the recording of state income tax adjustments**
Income Before Extraordinary Loss decreased $48 million to $133 million in 2007. The key drivers of the decrease were an $81 million increase in Operating Expenses and Other and a $6 million decrease in Gross Margin, partially offset by a decrease in Income Tax Expense of $39 million.

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

- Retail Margins decreased $47 million primarily due to higher capacity settlement expenses under the Interconnection Agreement. This decrease was partially offset by increases due to the impact of the Virginia base rate order issued in May 2007, the Virginia E&R and fuel cost recovery filings and increased demand in the residential class associated with favorable weather conditions. Cooling degree days increased 40% and heating degree days increased 18%.
- Margins from Off-system Sales increased $35 million primarily due to higher physical sales margins and higher trading margins.

Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $49 million primarily due to the following:
  - A $26 million increase resulting from a settlement agreement in the third quarter of 2007 related to alleged violations of the NSR provisions of the CAA. The $26 million represents APCo’s allocation of the settlement. See “Federal EPA Complaint and Notice of Violation” section of Note 6.
  - A $15 million increase in steam maintenance expenses resulting from forced and planned outages in 2007 at the Amos and Kanawha River Plants.
  - A $6 million increase primarily related to an increase in uncollectible accounts under a contract dispute with Verizon Communications, Inc. related to pole attachment revenues.
Depreciation and Amortization expenses decreased $8 million primarily due to the following:
- A $6 million decrease resulting primarily from lower Virginia depreciation rates implemented retroactively to January 2006 partially offset by additional depreciation expense for the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006, and the Mountaineer scrubber, which was placed in service in February 2007.
- A $9 million decrease resulting from a net deferral of ARO costs as a regulatory asset as approved in APCo’s Virginia base rate case.

These decreases were partially offset by:
- A $7 million increase in net E&R deferrals and amortization.
- Carrying Costs Income increased $5 million primarily due to carrying costs associated with the Virginia E&R case.
- Other Income decreased $11 million primarily due to lower interest income from the Utility Money Pool of $4 million. In addition, the equity component of AFUDC decreased $5 million resulting from lower CWIP balance after the Wyoming-Jacksons Ferry 765 kV line and the Mountaineer scrubber were placed into service.
- Interest Expense increased $36 million primarily due to a $22 million increase in interest expense from long-term debt issuances and short-term borrowings, an $11 million decrease in the debt component of AFUDC resulting from a lower CWIP balance after the Wyoming-Jackson Ferry 765 kV line and Mountaineer scrubber were placed into service and the reappllication of SFAS 71 and a $4 million increase in the interest on the Virginia provision for revenue collected subject to refund.
- Income Tax Expense decreased $39 million primarily due to a decrease in pretax book income and the recording of state income tax adjustments.

Financial Condition

Credit Ratings

Current ratings for APCo are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Moody’s</th>
<th>S&amp;P</th>
<th>Fitch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Senior Unsecured Debt</td>
<td>Baa2</td>
<td>BBB</td>
<td>BBB+</td>
</tr>
</tbody>
</table>

S&P currently has APCo on stable outlook, while Fitch has APCo on negative outlook. In February 2009, Moody’s changed its rating outlook for APCo from negative to stable due to recent rate recoveries in Virginia and West Virginia. If APCo receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Liquidity

In 2008, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting APCo’s access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on APCo since it relies on continuing access to capital to fund operations and capital expenditures.

APCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. APCo has $150 million of Senior Unsecured Notes that will mature in May 2009. To the extent refinancing is unavailable due to the challenging credit markets in 2009, APCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its maturity, continuing operations and capital expenditures.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of liquidity.
Cash Flow

Cash flows for 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th></th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td></td>
<td>(in thousands)</td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td></td>
</tr>
<tr>
<td>at Beginning of Period</td>
<td>$ 2,195</td>
</tr>
<tr>
<td>Cash Flows from (Used for):</td>
<td></td>
</tr>
<tr>
<td>Operating Activities</td>
<td>242,703</td>
</tr>
<tr>
<td>Investing Activities</td>
<td>(682,085)</td>
</tr>
<tr>
<td>Financing Activities</td>
<td>439,183</td>
</tr>
<tr>
<td>Net Increase (Decrease) in Cash and Cash Equivalents</td>
<td>(199)</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
<td>$ 1,996</td>
</tr>
</tbody>
</table>

**Operating Activities**

Net Cash Flows from Operating Activities were $243 million in 2008. APCo produced Net Income of $123 million during the period and noncash expense items of $257 million for Depreciation and Amortization, $146 million for Deferred Income Taxes and $48 million for Carrying Costs Income. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital primarily relates to a $190 million outflow in Fuel Over/Under-Recovery, Net as a result of a net under recovery of fuel cost in both Virginia and West Virginia due to higher fuel costs. In addition, the $138 million inflow from Accounts Payable included APCo’s provision for revenue refund of $77 million to be paid to the AEP West companies as part of the FERC’s recent order on the SIA.

Net Cash Flows from Operating Activities were $326 million in 2007. APCo produced Net Income of $55 million during the period and noncash expense items of $197 million for Depreciation and Amortization, $79 million for Extraordinary Loss, Net of Tax, $49 million for Deferred Income Taxes and $30 million for Carrying Costs Income. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had no significant items in 2007.

Net Cash Flows from Operating Activities were $468 million in 2006. APCo produced Net Income of $181 million during the period and noncash expense items of $206 million for Depreciation and Amortization and $17 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had no significant items in 2006.

**Investing Activities**

Net Cash Flows Used for Investing Activities during 2008, 2007 and 2006 primarily reflect APCo’s construction expenditures of $697 million, $746 million, and $893 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. Environmental upgrades include the installation of SCR equipment on APCo’s plants and the FGD project at the Amos and Mountaineer Plants. In February 2007, the FGD project was completed at the Mountaineer Plant. In 2006, capital projects for transmission expenditures were primarily related to the Wyoming-Jacksons Ferry 765 KV line placed into service in June 2006.
Financing Activities

Net Cash Flows from Financing Activities were $439 million in 2008. APCo issued $500 million in Senior Unsecured Notes and $245 million in Pollution Control Bonds. APCo also received capital contributions from the Parent of $200 million. These increases were partially offset by the retirement of $213 million of Pollution Control Bonds and $200 million of Senior Unsecured Notes. In addition, APCo reduced short-term borrowings from the Utility Money Pool by $80 million.

Net Cash Flows from Financing Activities were $410 million in 2007. APCo issued $500 million in Senior Unsecured Notes and $75 million in Pollution Control Bonds. APCo increased short-term borrowings from the Utility Money Pool by $240 million. APCo retired $325 million of Senior Unsecured Notes. In addition, APCo paid $44 million related to a long-term coal purchase contract amended in March 2006.

Net Cash Flows from Financing Activities were $413 million in 2006. APCo issued $500 million in Senior Unsecured Notes and $50 million in Pollution Control Bonds. APCo also received capital contributions from the Parent of $100 million and retired $100 million of First Mortgage Bonds. APCo reduced short-term borrowings from the Utility Money Pool by $159 million. In addition, APCo received funds of $68 million related to a long-term coal purchase contract amended in March 2006, partially offset by repayments of $24 million.
Summary Obligation Information

APCo’s contractual cash obligations include amounts reported on APCo’s Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes APCo’s contractual cash obligations at December 31, 2008:

<table>
<thead>
<tr>
<th>Payments Due by Period</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Less Than 1 year</td>
</tr>
<tr>
<td>Advances from Affiliates (a)</td>
<td>$ 194.9</td>
</tr>
<tr>
<td>Interest on Fixed Rate Portion of Long-term Debt (b)</td>
<td>176.0</td>
</tr>
<tr>
<td>Fixed Rate Portion of Long-term Debt (c)</td>
<td>150.0</td>
</tr>
<tr>
<td>Variable Rate Portion of Long-term Debt (d)</td>
<td>-</td>
</tr>
<tr>
<td>Capital Lease Obligations (e)</td>
<td>3.9</td>
</tr>
<tr>
<td>Noncancelable Operating Leases (e)</td>
<td>20.6</td>
</tr>
<tr>
<td>Fuel Purchase Contracts (f)</td>
<td>990.5</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (g)</td>
<td>14.3</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (h)</td>
<td>85.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 1,635.4</strong></td>
</tr>
</tbody>
</table>

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 14. Represents principal only excluding interest.
(d) See Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 1.05% and 1.52% at December 31, 2008.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

APCo’s FIN 48 liabilities of $16 million are not included above because APCo cannot reasonably estimate the cash flows by period.

AEP’s minimum pension funding requirements are not included in the above table. As of December 31, 2008, the decline in pension asset values will not require AEP to make a contribution in 2009. AEP will need to make minimum contributions to the pension plan of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

In addition to the amounts disclosed in the contractual cash obligations table above, APCo makes additional commitments in the normal course of business. APCo’s commitments outstanding at December 31, 2008 under these agreements are summarized in the table below:

<table>
<thead>
<tr>
<th>Amount of Commitment Expiration Per Period</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Less Than 1 year</td>
</tr>
<tr>
<td>Standby Letters of Credit (a)</td>
<td>$ 126.7</td>
</tr>
</tbody>
</table>

(a) APCo has issued standby letters of credit. These letters of credit cover insurance programs, security deposits and debt service reserves. All of these letters of credit were issued in APCo’s ordinary course of business. The maximum future payments of these letters of credit are $126.7 million maturing in June 2009. There is no recourse to third parties in the event these letters of credit are drawn. See “Letters of Credit” section of Note 6.
**Significant Factors**

**Litigation and Regulatory Activity**

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect APCo’s net income, financial condition and cash flows.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of relevant factors.

**Critical Accounting Estimates**

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

**Adoption of New Accounting Pronouncements**

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.
Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section. The following tables provide information about AEP’s risk management activities’ effect on APCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in APCo’s Consolidated Balance Sheet as of December 31, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet
December 31, 2008
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>MTM Risk Management Contracts</th>
<th>Cash Flow &amp; Fair Value Hedges</th>
<th>DETM Assignment (a)</th>
<th>Collateral Deposits</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets</td>
<td>$61,040</td>
<td>$5,041</td>
<td>-</td>
<td>$(941)</td>
<td>$65,140</td>
</tr>
<tr>
<td>Noncurrent Assets</td>
<td>52,163</td>
<td>180</td>
<td>-</td>
<td>(1,248)</td>
<td>51,095</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Assets</strong></td>
<td><strong>113,203</strong></td>
<td><strong>5,221</strong></td>
<td>-</td>
<td><strong>(2,189)</strong></td>
<td><strong>116,235</strong></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>(29,057)</td>
<td>(1,103)</td>
<td>(2,737)</td>
<td>2,277</td>
<td>(30,620)</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>(27,210)</td>
<td>(29)</td>
<td>(2,493)</td>
<td>3,344</td>
<td>(26,388)</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Liabilities</strong></td>
<td><strong>(56,267)</strong></td>
<td><strong>(1,132)</strong></td>
<td><strong>(5,230)</strong></td>
<td><strong>5,621</strong></td>
<td><strong>(57,008)</strong></td>
</tr>
<tr>
<td>Total MTM Derivative Contract Net Assets (Liabilities)</td>
<td>$56,936</td>
<td>$4,089</td>
<td>$(5,230)</td>
<td>$3,432</td>
<td>$59,227</td>
</tr>
</tbody>
</table>

(a) See “Natural Gas Contracts with DETM” section of Note 15.
## MTM Risk Management Contract Net Assets
### Year Ended December 31, 2008
### (in thousands)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total MTM Risk Management Contract Net Assets at December 31, 2007</strong></td>
<td>$45,870</td>
</tr>
<tr>
<td>(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period</td>
<td>$(13,220)</td>
</tr>
<tr>
<td>Fair Value of New Contracts at Inception When Entered During the Period (a)</td>
<td>-</td>
</tr>
<tr>
<td>Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period</td>
<td>-</td>
</tr>
<tr>
<td>Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)</td>
<td>646</td>
</tr>
<tr>
<td>Changes in Fair Value Due to Market Fluctuations During the Period (c)</td>
<td>$(430)</td>
</tr>
<tr>
<td>Changes in Fair Value Allocated to Regulated Jurisdictions (d)</td>
<td>24,070</td>
</tr>
<tr>
<td><strong>Total MTM Risk Management Contract Net Assets</strong></td>
<td>$56,936</td>
</tr>
<tr>
<td>Net Cash Flow &amp; Fair Value Hedge Contracts</td>
<td>4,089</td>
</tr>
<tr>
<td>DETM Assignment (e)</td>
<td>$(5,230)</td>
</tr>
<tr>
<td>Collateral Deposits</td>
<td>3,432</td>
</tr>
<tr>
<td><strong>Ending Net Risk Management Assets at December 31, 2008</strong></td>
<td>$59,227</td>
</tr>
</tbody>
</table>

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Represents the impact of applying AEP’s credit risk when measuring the fair value of derivative liabilities according to SFAS 157.

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

(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

(e) See “Natural Gas Contracts with DETM” section of Note 15.
Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

<table>
<thead>
<tr>
<th>Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets</th>
<th>Fair Value of Contracts as of December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>$ (2,682)</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>23,006</td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td>6,939</td>
</tr>
<tr>
<td>Total</td>
<td>27,263</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (d)</td>
<td>4,720</td>
</tr>
<tr>
<td>Total MTM Risk Management Contract Net Assets (Liabilities)</td>
<td>$ 31,983</td>
</tr>
</tbody>
</table>

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

(d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contracts.

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

APCo is exposed to market fluctuations in energy commodity prices impacting power operations. Management monitors these risks on future operations and may use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate exposure on anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate exposure.

Management uses foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designates qualifying instruments as cash flow hedges. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on APCo’s Consolidated Balance Sheets and the reasons for the changes from December 31, 2007 to December 31, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.
Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2008
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Power</th>
<th>Interest Rate</th>
<th>Foreign Currency</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beginning Balance in AOCI</td>
<td>$ 783</td>
<td>(6,602)</td>
<td>$ (125)</td>
<td>(5,944)</td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>2,623</td>
<td>(3,113)</td>
<td>67</td>
<td>(423)</td>
</tr>
<tr>
<td>Reclassifications from AOCI to</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income for Cash Flow Hedges Settled</td>
<td>(680)</td>
<td>1,648</td>
<td>7</td>
<td>975</td>
</tr>
<tr>
<td>Ending Balance in AOCI</td>
<td>$ 2,726</td>
<td>(8,067)</td>
<td>$ (51)</td>
<td>(5,392)</td>
</tr>
</tbody>
</table>

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $959 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2008, a near term typical change in commodity prices is not expected to have a material effect on net income, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years ended:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008 (in thousands)</th>
<th>December 31, 2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>End</td>
<td>$176</td>
<td>$455</td>
</tr>
<tr>
<td>High</td>
<td>$1,096</td>
<td>$2,328</td>
</tr>
<tr>
<td>Average</td>
<td>$396</td>
<td>$569</td>
</tr>
<tr>
<td>Low</td>
<td>$161</td>
<td>$117</td>
</tr>
</tbody>
</table>

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management’s backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes APCo’s VaR calculation is conservative.

As APCo’s VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand its exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translated into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which APCo’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on APCo’s debt portfolio is $7.6 million.
### Consolidated Statements of Income

For the Years Ended December 31, 2008, 2007 and 2006

#### (in thousands)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REVENUES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Generation, Transmission and Distribution</td>
<td>$2,542,222</td>
<td>$2,333,448</td>
<td>$2,145,639</td>
</tr>
<tr>
<td>Sales to AEP Affiliates</td>
<td>328,735</td>
<td>263,066</td>
<td>238,592</td>
</tr>
<tr>
<td>Other</td>
<td>18,199</td>
<td>10,755</td>
<td>9,797</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>2,889,156</td>
<td>2,607,269</td>
<td>2,394,028</td>
</tr>
</tbody>
</table>

| **EXPENSES**   |           |           |           |
| Fuel and Other Consumables Used for Electric Generation | 710,115   | 708,127   | 638,862   |
| Purchased Electricity for Resale                       | 215,413   | 165,901   | 123,592   |
| Purchased Electricity from AEP Affiliates              | 785,191   | 600,293   | 492,756   |
| Other Operation                                        | 297,818   | 319,260   | 284,350   |
| Maintenance                                            | 209,766   | 204,763   | 190,697   |
| Depreciation and Amortization                          | 256,626   | 197,259   | 205,666   |
| Taxes Other Than Income Taxes                          | 101,251   | 90,840    | 92,462    |
| **TOTAL**                                              | 2,576,180 | 2,286,443 | 2,028,385 |

**OPERATING INCOME**

312,976

**Other Income (Expense):**

- **Interest Income**
  - 2008: 6,371
  - 2007: 2,676
  - 2006: 8,648
- **Carrying Costs Income**
  - 2008: 48,249
  - 2007: 30,179
  - 2006: 25,666
- **Allowance for Equity Funds Used During Construction**
  - 2008: 8,938
  - 2007: 7,337
  - 2006: 12,014
- **Interest Expense**
  - (2008): (209,733)
  - (2007): (165,405)
  - (2006): (129,106)

**INCOME BEFORE INCOME TAX EXPENSE**

166,801

**Income Tax Expense**

43,938

**INCOME BEFORE EXTRAORDINARY LOSS**

122,863

**EXTRAORDINARY LOSS – REAPPLICATION OF REGULATORY ACCOUNTING FOR GENERATION, NET OF TAX**

- (78,763)

**NET INCOME**

122,863

**Preferred Stock Dividend Requirements Including Capital Stock Expense**

942

**EARNINGS APPLICABLE TO COMMON STOCK**

$121,921

$53,784

$180,497

*The common stock of APCo is wholly-owned by AEP.*

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Common Stock</th>
<th>Paid-in Capital</th>
<th>Retained Earnings</th>
<th>Accumulated Other Comprehensive Income (Loss)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>DECEMBER 31, 2005</td>
<td>$ 260,458</td>
<td>$ 924,837</td>
<td>$ 635,016</td>
<td>$(16,610)</td>
<td>$ 1,803,701</td>
</tr>
</tbody>
</table>

Capital Contribution from Parent 100,000
Common Stock Dividends (10,000)
Preferred Stock Dividends (800)
Capital Stock Expense 157
TOTAL 1,892,906

COMPREHENSIVE INCOME
Other Comprehensive Income (Loss), Net of Taxes:
Cash Flow Hedges, Net of Tax of $7,471 13,874
Minimum Pension Liability, Net of Tax of $7 (14)
TOTAL COMPREHENSIVE INCOME 181,449
Minimum Pension Liability Elimination, Net of Tax of $109 203
SFAS 158 Adoption, Net of Tax of $28,132 (52,244)
TOTAL 2,036,174

DECEMBER 31, 2006
FIN 48 Adoption, Net of Tax (2,685)
Common Stock Dividends (25,000)
Preferred Stock Dividends (799)
Capital Stock Expense 155
TOTAL 2,007,692

COMPREHENSIVE INCOME
Other Comprehensive Income (Loss), Net of Taxes:
Cash Flow Hedges, Net of Tax of $1,829 (3,397)
SFAS 158 Adoption Costs Established as Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6,055 11,245
Pension and OPEB Funded Status, Net of Tax of $6,330 11,756
TOTAL COMPREHENSIVE INCOME 74,340

DECEMBER 31, 2007
EITF 06-10 Adoption, Net of Tax of $1,175 (2,181)
SFAS 157 Adoption, Net of Tax of $154 (286)
Capital Contribution from Parent 200,000
Preferred Stock Dividends (799)
Capital Stock Expense 143
TOTAL 2,278,766

COMPREHENSIVE INCOME
Other Comprehensive Income (Loss), Net of Taxes:
Cash Flow Hedges, Net of Tax of $297 552
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,794 3,333
Pension and OPEB Funded Status, Net of Tax of $15,574 (28,923)
TOTAL COMPREHENSIVE INCOME 97,825

DECEMBER 31, 2008
$ 260,458 $ 1,225,292 $ 951,066 $(60,225) $ 2,376,591

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
# APPALACHIAN POWER COMPANY AND SUBSIDIARIES
## CONSOLIDATED BALANCE SHEETS
### ASSETS
#### December 31, 2008 and 2007
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CURRENT ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$ 1,996</td>
<td>$ 2,195</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customers</td>
<td>175,709</td>
<td>176,834</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>110,982</td>
<td>113,582</td>
</tr>
<tr>
<td>Accrued Unbilled Revenues</td>
<td>55,733</td>
<td>38,397</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>498</td>
<td>2,823</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts</td>
<td>(6,176)</td>
<td>(13,948)</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>336,746</td>
<td>317,688</td>
</tr>
<tr>
<td>Fuel</td>
<td>131,239</td>
<td>82,203</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>76,260</td>
<td>76,685</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>65,140</td>
<td>62,955</td>
</tr>
<tr>
<td>Regulatory Asset for Under-Recovered Fuel Costs</td>
<td>165,906</td>
<td>-</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>61,256</td>
<td>16,369</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>838,543</td>
<td>558,095</td>
</tr>
</tbody>
</table>

| **PROPERTY, PLANT AND EQUIPMENT** |          |
| Electric:                        |          |
| Production                       | 3,708,850| 3,625,788|
| Transmission                     | 1,754,192| 1,675,081|
| Distribution                     | 2,499,974| 2,372,687|
| Other                            | 358,873  | 351,827  |
| Construction Work in Progress    | 1,106,032| 713,063  |
| **Total**                        | 9,427,921| 8,738,446|
| Accumulated Depreciation and Amortization | 2,675,784| 2,591,833|
| **TOTAL - NET**                  | 6,752,137| 6,146,613|

| **OTHER NONCURRENT ASSETS** |          |
| Regulatory Assets            | 999,061  | 652,739  |
| Long-term Risk Management Assets | 51,095  | 72,366   |
| Deferred Charges and Other   | 121,828  | 191,871  |
| **TOTAL**                     | 1,171,984| 916,976  |

| **TOTAL ASSETS**              | $ 8,762,664| $ 7,621,684|

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
## APPALACHIAN POWER COMPANY AND SUBSIDIARIES
### CONSOLIDATED BALANCE SHEETS
### LIABILITIES AND SHAREHOLDERS’ EQUITY
### December 31, 2008 and 2007

### CURRENT LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates</td>
<td>$194,888</td>
<td>$275,257</td>
</tr>
<tr>
<td>Accounts Payable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>358,081</td>
<td>241,871</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>206,813</td>
<td>106,852</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year – Nonaffiliated</td>
<td>150,017</td>
<td>239,732</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>30,620</td>
<td>51,708</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>54,086</td>
<td>45,920</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>65,550</td>
<td>58,519</td>
</tr>
<tr>
<td>Accrued Interest</td>
<td>47,804</td>
<td>41,699</td>
</tr>
<tr>
<td>Other</td>
<td>113,655</td>
<td>139,476</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,221,514</td>
<td>1,201,034</td>
</tr>
</tbody>
</table>

### NONCURRENT LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Debt – Nonaffiliated</td>
<td>2,924,495</td>
<td>2,507,567</td>
</tr>
<tr>
<td>Long-term Debt – Affiliated</td>
<td>100,000</td>
<td>100,000</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>26,388</td>
<td>47,357</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>1,131,164</td>
<td>948,891</td>
</tr>
<tr>
<td>Regulatory Liabilities and Deferred Investment Tax Credits</td>
<td>521,508</td>
<td>505,556</td>
</tr>
<tr>
<td>Employee Benefits and Pension Obligations</td>
<td>331,000</td>
<td>106,678</td>
</tr>
<tr>
<td>Deferred Credits and Other</td>
<td>112,252</td>
<td>104,817</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>5,146,807</td>
<td>4,320,866</td>
</tr>
</tbody>
</table>

### TOTAL LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>17,752</td>
<td>17,752</td>
</tr>
<tr>
<td>Commitments and Contingencies (Note 6)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### COMMON SHAREHOLDER’S EQUITY

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Stock – No Par Value:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Authorized – 30,000,000 Shares</td>
<td>260,458</td>
<td>260,458</td>
</tr>
<tr>
<td>Outstanding – 13,499,500 Shares</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Paid-in Capital</td>
<td>1,225,292</td>
<td>1,025,149</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>951,066</td>
<td>831,612</td>
</tr>
<tr>
<td>Accumulated Other Comprehensive Income (Loss)</td>
<td>(60,225)</td>
<td>(35,187)</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>2,376,591</td>
<td>2,082,032</td>
</tr>
</tbody>
</table>

### TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$8,762,664</td>
<td>$7,621,684</td>
</tr>
</tbody>
</table>

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
**Consolidated Statements of Cash Flows**

For the Years Ended December 31, 2008, 2007 and 2006

(in thousands)

<table>
<thead>
<tr>
<th>OPERATING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$122,863</td>
<td>$54,736</td>
<td>$181,449</td>
</tr>
<tr>
<td><strong>Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>256,626</td>
<td>197,259</td>
<td>205,666</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>145,594</td>
<td>48,962</td>
<td>17,225</td>
</tr>
<tr>
<td>Extraordinary Loss, Net of Tax</td>
<td>-</td>
<td>78,763</td>
<td>-</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>(48,249)</td>
<td>(30,179)</td>
<td>(25,666)</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>(8,938)</td>
<td>(7,337)</td>
<td>(12,014)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>(20,555)</td>
<td>(4,999)</td>
<td>(16,139)</td>
</tr>
<tr>
<td>Change in Regulatory Assets</td>
<td>(73,602)</td>
<td>(6,385)</td>
<td>(5,706)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>(12,020)</td>
<td>(21,286)</td>
<td>(50,145)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>(7,335)</td>
<td>9,042</td>
<td>54,745</td>
</tr>
<tr>
<td><strong>Changes in Certain Components of Working Capital:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts Receivable, Net</td>
<td>(19,058)</td>
<td>(10,370)</td>
<td>21,412</td>
</tr>
<tr>
<td>Fuel, Materials and Supplies</td>
<td>(43,748)</td>
<td>(8,435)</td>
<td>(13,688)</td>
</tr>
<tr>
<td>Accounts Payable</td>
<td>137,704</td>
<td>(13,226)</td>
<td>37,533</td>
</tr>
<tr>
<td>Accrued Taxes, Net</td>
<td>(5,496)</td>
<td>(2,740)</td>
<td>39,454</td>
</tr>
<tr>
<td>Fuel Over/Under-Recovery, Net</td>
<td>(189,543)</td>
<td>41,967</td>
<td>11,532</td>
</tr>
<tr>
<td>Other Current Assets</td>
<td>(18,984)</td>
<td>3,369</td>
<td>17,841</td>
</tr>
<tr>
<td>Other Current Liabilities</td>
<td>(674)</td>
<td>861</td>
<td>(945)</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Operating Activities</strong></td>
<td>242,703</td>
<td>325,629</td>
<td>468,275</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>INVESTING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Expenditures</td>
<td>(696,767)</td>
<td>(745,830)</td>
<td>(892,816)</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(1,685)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>17,041</td>
<td>9,020</td>
<td>13,364</td>
</tr>
<tr>
<td><strong>Net Cash Flows Used for Investing Activities</strong></td>
<td>(682,085)</td>
<td>(735,949)</td>
<td>(880,397)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FINANCING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Contribution from Parent</td>
<td>200,000</td>
<td>-</td>
<td>100,000</td>
</tr>
<tr>
<td>Issuance of Long-term Debt – Nonaffiliated</td>
<td>735,799</td>
<td>568,778</td>
<td>561,710</td>
</tr>
<tr>
<td>Change in Advances from Affiliates, Net</td>
<td>(80,369)</td>
<td>240,282</td>
<td>(159,158)</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Nonaffiliated</td>
<td>(412,789)</td>
<td>(325,013)</td>
<td>(117,511)</td>
</tr>
<tr>
<td>Retirement of Cumulative Preferred Stock</td>
<td>-</td>
<td>(9)</td>
<td>(16)</td>
</tr>
<tr>
<td>Principal Payments for Capital Lease Obligations</td>
<td>(3,922)</td>
<td>(4,402)</td>
<td>(5,166)</td>
</tr>
<tr>
<td>Funds from Amended Coal Contract</td>
<td>-</td>
<td>-</td>
<td>68,078</td>
</tr>
<tr>
<td>Amortization of Funds from Amended Coal Contract</td>
<td>-</td>
<td>(43,640)</td>
<td>(24,438)</td>
</tr>
<tr>
<td>Dividends Paid on Common Stock</td>
<td>-</td>
<td>(25,000)</td>
<td>(10,000)</td>
</tr>
<tr>
<td>Dividends Paid on Cumulative Preferred Stock</td>
<td>(799)</td>
<td>(799)</td>
<td>(800)</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Financing Activities</strong></td>
<td>439,183</td>
<td>410,197</td>
<td>412,699</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Net Increase (Decrease) in Cash and Cash Equivalents</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>(199)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at Beginning of Period</strong></td>
<td>2,195</td>
<td>2,318</td>
<td>1,741</td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at End of Period</strong></td>
<td>$1,996</td>
<td>$2,195</td>
<td>$2,318</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SUPPLEMENTARY INFORMATION</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash Paid for Interest, Net of Capitalized Amounts</td>
<td>$177,531</td>
<td>$148,805</td>
<td>$118,220</td>
</tr>
<tr>
<td>Net Cash Paid (Received) for Income Taxes</td>
<td>(72,973)</td>
<td>26,189</td>
<td>50,830</td>
</tr>
<tr>
<td>Noncash Acquisitions Under Capital Leases</td>
<td>3,242</td>
<td>3,636</td>
<td>3,017</td>
</tr>
<tr>
<td>Construction Expenditures Included in Accounts Payable at December 31,</td>
<td>185,469</td>
<td>107,001</td>
<td>130,558</td>
</tr>
<tr>
<td>Revenue Refund Included in Accounts Payable at December 31,</td>
<td>77,139</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
The notes to APCo’s consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page H-1.

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<tr>
<td>Note 1</td>
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<td>Note 4</td>
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<td>Note 5</td>
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<td>Note 6</td>
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<td>Note 8</td>
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<td>Note 10</td>
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<td>Note 11</td>
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<td>Note 12</td>
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<td>Note 15</td>
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<td>Note 16</td>
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<td>Note 17</td>
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</table>
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 8 to the consolidated financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
The management of Appalachian Power Company and subsidiaries (APCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. APCo’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of APCo’s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, APCo’s internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of APCo’s registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by APCo’s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit APCo to provide only management’s report in this annual report.
COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES
As a public utility, CSPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 749,000 retail customers in central and southern Ohio. CSPCo consolidates Colomet, Inc. and Conesville Coal Preparation Company, its wholly-owned subsidiaries. Effective September 2008, Simco, Inc. merged into Conesville Coal Preparation Company. As a member of the AEP Power Pool, CSPCo shares the revenues and the costs of the AEP Power Pool’s sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool’s generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member’s prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member’s percentage share of revenues and costs.

In March 2007, CSPCo and AEGCo entered into a 10-year unit power agreement for the entire output from the Lawrenceburg Plant with an option for an additional 2-year period. CSPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant operates.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies’ and AEP West companies’ allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, 2006 net income and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on CSPCo’s behalf. CSPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. CSPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

CSPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.
Results of Operations
2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008

<table>
<thead>
<tr>
<th>Year Ended December 31, 2007</th>
<th>$ 258</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Income</strong></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Changes in Gross Margin:</th>
<th></th>
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<tbody>
<tr>
<td>Retail Margins</td>
<td>47</td>
</tr>
<tr>
<td>Off-system Sales</td>
<td>4</td>
</tr>
<tr>
<td>Transmission Revenues</td>
<td>4</td>
</tr>
<tr>
<td>Other</td>
<td>1</td>
</tr>
<tr>
<td><strong>Total Change in Gross Margin</strong></td>
<td>56</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Changes in Operating Expenses and Other:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Other Operation and Maintenance</td>
<td>(84)</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>11</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>(7)</td>
</tr>
<tr>
<td>Other Income</td>
<td>5</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(22)</td>
</tr>
<tr>
<td><strong>Total Change in Operating Expenses and Other</strong></td>
<td>(97)</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>20</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year Ended December 31, 2008</th>
<th>$ 237</th>
</tr>
</thead>
</table>

Net Income decreased $21 million to $237 million in 2008. The key driver of the decrease was a $97 million increase in Operating Expenses and Other, partially offset by a $56 million increase in Gross Margin and a $20 million decrease in Income Tax Expense.

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

- Retail Margins increased $47 million primarily due to:
  - A $145 million increase related to a net increase in rates implemented.
  - A $39 million decrease in capacity settlement charges related to CSPCo’s Unit Power Agreement (UPA) for AEGCo’s Lawrenceburg Plant, which began in May 2007.
  - A $29 million increase primarily related to increased usage by Ormet, a major industrial customer. These increases were partially offset by:
    - A $65 million increase in fuel, allowance and consumables expenses. CSPCo has applied for an active fuel clause in its Ohio Electric Security Plan to be effective January 1, 2009. See “Ohio Electric Security Plan Filings” section of Note 4.
    - A $35 million decrease in residential, commercial and industrial sales partially due to the economic slowdown in the second half of 2008.
    - A $30 million provision for refund of off-system sales margins in December 2008 as ordered by the FERC related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
    - A $14 million decrease in residential and commercial revenue primarily due to a 20% decrease in cooling degree days.
- Margins from Off-system Sales increased $4 million primarily due to increased physical sales margins driven by higher prices, partially offset by lower trading margins.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $84 million primarily due to:
  - A $33 million increase in recoverable PJM expenses.
  - A $16 million increase in expenses related to CSPCo’s Unit Power Agreement for AEGCo’s Lawrenceburg Plant which began in May 2007.
  - A $14 million increase in steam plant maintenance expenses and a $4 million increase in removal expenses primarily related to work performed at the Conesville Plant.
  - A $13 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $4 million increase in transmission maintenance expenses primarily for maintaining overhead lines.
  - A $4 million increase in miscellaneous distribution expenses.

  These increases were partially offset by:
  - A $15 million decrease resulting from a settlement agreement in the third quarter of 2007 related to alleged violations of the NSR provisions of the CAA. The $15 million represents CSPCo’s allocation of the settlement. See “Federal EPA Complaint and Notice of Violation” section of Note 6.
  - Depreciation and Amortization expense decreased $11 million primarily due to the amortization of regulatory credits related to energy sales to Ormet at below market rates.
  - Taxes Other Than Income Taxes increased $7 million due to increases in taxable property value.
  - Other Income increased $5 million primarily due to interest income on federal tax refunds.
  - Interest Expense increased $22 million due to $14 million of interest expense on the December 2008 provision for refund of off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4. In addition, interest expense increased due to increases in long-term borrowings.
  - Income Tax Expense decreased $20 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments.

**Critical Accounting Estimates**

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

**Adoption of New Accounting Pronouncements**

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.
Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section for disclosures about risk management activities.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which CSPCo’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on CSPCo’s debt portfolio is $733 thousand.
## COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
### CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
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<tbody>
<tr>
<td><strong>REVENUES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Generation, Transmission and Distribution</td>
<td>$2,079,610</td>
<td>$1,893,045</td>
<td>$1,715,542</td>
</tr>
<tr>
<td>Sales to AEP Affiliates</td>
<td>122,949</td>
<td>143,112</td>
<td>85,726</td>
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<tr>
<td>Other</td>
<td>5,542</td>
<td>7,155</td>
<td>5,467</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>2,208,101</td>
<td>2,043,312</td>
<td>1,806,735</td>
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<tr>
<td><strong>EXPENSES</strong></td>
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</tr>
<tr>
<td>Fuel and Other Consumables Used for Electric Generation</td>
<td>360,792</td>
<td>342,149</td>
<td>294,841</td>
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<tr>
<td>Purchased Electricity for Resale</td>
<td>197,943</td>
<td>158,526</td>
<td>115,420</td>
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<tr>
<td>Purchased Electricity from AEP Affiliates</td>
<td>413,518</td>
<td>362,648</td>
<td>365,510</td>
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<tr>
<td>Other Operation</td>
<td>348,051</td>
<td>280,705</td>
<td>256,479</td>
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<tr>
<td>Maintenance</td>
<td>109,335</td>
<td>93,157</td>
<td>88,654</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>186,746</td>
<td>197,303</td>
<td>193,251</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>168,028</td>
<td>161,463</td>
<td>154,930</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,784,413</td>
<td>1,595,951</td>
<td>1,469,085</td>
</tr>
<tr>
<td><strong>OPERATING INCOME</strong></td>
<td>423,688</td>
<td>447,361</td>
<td>337,650</td>
</tr>
<tr>
<td>Other Income (Expense):</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest Income</td>
<td>5,334</td>
<td>1,943</td>
<td>8,885</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>6,551</td>
<td>4,758</td>
<td>4,122</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>3,364</td>
<td>3,036</td>
<td>1,865</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(92,068)</td>
<td>(69,625)</td>
<td>(66,100)</td>
</tr>
<tr>
<td><strong>INCOME BEFORE INCOME TAX EXPENSE</strong></td>
<td>346,869</td>
<td>387,473</td>
<td>286,422</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>109,739</td>
<td>129,385</td>
<td>100,843</td>
</tr>
<tr>
<td><strong>NET INCOME</strong></td>
<td>237,130</td>
<td>258,088</td>
<td>185,579</td>
</tr>
<tr>
<td>Capital Stock Expense</td>
<td>157</td>
<td>157</td>
<td>157</td>
</tr>
<tr>
<td><strong>EARNINGS APPLICABLE TO COMMON STOCK</strong></td>
<td>$236,973</td>
<td>$257,931</td>
<td>$185,422</td>
</tr>
</tbody>
</table>

*The common stock of CSPCo is wholly-owned by AEP.*

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Common Stock</th>
<th>Paid-in Capital</th>
<th>Retained Earnings</th>
<th>Accumulated Other Comprehensive Income (Loss)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DECEMBER 31, 2005</strong></td>
<td>$ 41,026</td>
<td>$ 580,035</td>
<td>$ 361,365</td>
<td>$ (880)</td>
<td>$ 981,546</td>
</tr>
<tr>
<td>Common Stock Dividends</td>
<td>(90,000)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital Stock Expense</td>
<td>157</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>891,546</td>
</tr>
</tbody>
</table>

**COMPREHENSIVE INCOME**
Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $2,292
- Minimum Pension Liability, Net of Tax of $2

**NET INCOME**

|                  |              |                 |                   |                                             |         |
| **TOTAL COMPREHENSIVE INCOME** |              |                 |                   |                                             |         |
| Minimum Pension Liability Elimination, Net of Tax of $14 | 25           |                 |                   |                                             |         |
| SFAS 158 Adoption, Net of Tax of $13,670 | (25,386)     | (25,386)        |                   |                                             |         |
| **DECEMBER 31, 2006** | 41,026       | 580,192         | 456,787           | (21,988)                                    | 1,056,017 |
| FIN 48 Adoption, Net of Tax | (3,022)      |                 |                   |                                             |         |
| Common Stock Dividends | (150,000)    |                 |                   |                                             |         |
| Capital Stock Expense | 157          |                 |                   |                                             |         |
| **TOTAL**                  |              |                 |                   |                                             | 902,995 |

**COMPREHENSIVE INCOME**
Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $2,180
- Pension and OPEB Funded Status, Net of Tax of $3,900

**NET INCOME**

|                  |              |                 |                   |                                             |         |
| **TOTAL COMPREHENSIVE INCOME** |              |                 |                   |                                             |         |
| Minimum Pension Liability Elimination, Net of Tax of $14 | 25           |                 |                   |                                             |         |
| SFAS 157 Adoption, Net of Tax of $170 | (316)        | (316)           |                   |                                             |         |
| **DECEMBER 31, 2007** | 41,026       | 580,349         | 561,696           | (18,794)                                    | 1,164,277 |
| EITF 06-10 Adoption, Net of Tax of $589 | (1,095)      |                 |                   |                                             |         |
| SFAS 157 Adoption, Net of Tax of $170 | (316)        | (316)           |                   |                                             |         |
| Common Stock Dividends | (122,500)    |                 |                   |                                             |         |
| Capital Stock Expense | 157          |                 |                   |                                             |         |
| **TOTAL**                  |              |                 |                   |                                             | 1,040,366 |

**COMPREHENSIVE INCOME**
Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $1,174
- Amortization of Pension and OPEB Deferred Costs, Net of Tax of $607
- Pension and OPEB Funded Status, Net of Tax of $19,137

**NET INCOME**

|                  |              |                 |                   |                                             |         |
| **TOTAL COMPREHENSIVE INCOME** |              |                 |                   |                                             |         |
| **DECEMBER 31, 2008** | 41,026       | 580,506         | 674,758           | (51,025)                                    | 1,245,265 |

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2008 and 2007
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$ 1,063</td>
<td>$ 1,389</td>
</tr>
<tr>
<td>Other Cash Deposits</td>
<td>32,300</td>
<td>53,760</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customers</td>
<td>56,008</td>
<td>57,268</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>44,235</td>
<td>32,852</td>
</tr>
<tr>
<td>Accrued Unbilled Revenues</td>
<td>18,359</td>
<td>14,815</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>11,546</td>
<td>9,905</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts</td>
<td>(2,895)</td>
<td>(2,563)</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>127,253</td>
<td>112,277</td>
</tr>
<tr>
<td>Fuel</td>
<td>42,075</td>
<td>35,849</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>33,781</td>
<td>36,626</td>
</tr>
<tr>
<td>Emission Allowances</td>
<td>20,211</td>
<td>16,811</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>35,984</td>
<td>33,558</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>41,493</td>
<td>9,960</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>334,160</strong></td>
<td><strong>300,230</strong></td>
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</tbody>
</table>

**PROPERTY, PLANT AND EQUIPMENT**

<table>
<thead>
<tr>
<th></th>
<th><strong>2008</strong></th>
<th><strong>2007</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>2,326,056</td>
<td>2,072,564</td>
</tr>
<tr>
<td>Transmission</td>
<td>574,018</td>
<td>510,107</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,625,000</td>
<td>1,552,999</td>
</tr>
<tr>
<td>Other</td>
<td>211,088</td>
<td>198,476</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>394,918</td>
<td>415,327</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>5,131,080</strong></td>
<td><strong>4,749,473</strong></td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td><strong>1,781,866</strong></td>
<td><strong>1,697,793</strong></td>
</tr>
<tr>
<td><strong>TOTAL - NET</strong></td>
<td><strong>3,349,214</strong></td>
<td><strong>3,051,680</strong></td>
</tr>
</tbody>
</table>

**OTHER NONCURRENT ASSETS**

<table>
<thead>
<tr>
<th></th>
<th><strong>2008</strong></th>
<th><strong>2007</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Assets</td>
<td>298,357</td>
<td>235,883</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>28,461</td>
<td>41,852</td>
</tr>
<tr>
<td>Deferred Charges and Other</td>
<td>125,814</td>
<td>181,563</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>452,632</strong></td>
<td><strong>459,298</strong></td>
</tr>
</tbody>
</table>

**TOTAL ASSETS**

<table>
<thead>
<tr>
<th></th>
<th><strong>2008</strong></th>
<th><strong>2007</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>$ 4,136,006</strong></td>
<td><strong>$ 3,811,208</strong></td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER’S EQUITY
December 31, 2008 and 2007

<table>
<thead>
<tr>
<th></th>
<th>2008 (in thousands)</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CURRENT LIABILITIES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advances from Affiliates</td>
<td>$ 74,865</td>
<td>$ 95,199</td>
</tr>
<tr>
<td>Accounts Payable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>131,417</td>
<td>113,290</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>120,420</td>
<td>65,292</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year – Nonaffiliated</td>
<td>-</td>
<td>112,000</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>16,490</td>
<td>28,237</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>30,145</td>
<td>43,095</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>185,293</td>
<td>179,831</td>
</tr>
<tr>
<td>Other</td>
<td>82,678</td>
<td>96,892</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>641,308</td>
<td>733,836</td>
</tr>
</tbody>
</table>

| **NONCURRENT LIABILITIES**           |                     |      |
| Long-term Debt – Nonaffiliated       | 1,343,594           | 1,086,224 |
| Long-term Debt – Affiliated          | 100,000             | 100,000 |
| Long-term Risk Management Liabilities| 14,774              | 27,419 |
| Deferred Income Taxes                | 435,773             | 437,306 |
| Regulatory Liabilities and Deferred Investment Tax Credits| 161,102 | 165,635 |
| Employee Benefits and Pension Obligations | 148,123   | 36,636 |
| Deferred Credits and Other           | 46,067              | 59,875 |
| **TOTAL**                            | 2,249,433           | 1,913,095 |

**TOTAL LIABILITIES**                | 2,890,741           | 2,646,931 |

Commitments and Contingencies (Note 6)

**COMMON SHAREHOLDER’S EQUITY**      |                     |      |
Common Stock – No Par Value:          |                     |      |
  Authorized – 24,000,000 Shares      | 41,026              | 41,026 |
  Outstanding – 16,410,426 Shares     |                    |      |
Paid-in Capital                       | 580,506             | 580,349 |
Retained Earnings                    | 674,758             | 561,696 |
Accumulated Other Comprehensive Income (Loss) | (51,025) | (18,794) |
**TOTAL**                             | 1,245,265           | 1,164,277 |

**TOTAL LIABILITIES AND SHAREHOLDER’S EQUITY** | $ 4,136,006 | $ 3,811,208 |

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th>OPERATING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$237,130</td>
<td>$258,088</td>
<td>$185,579</td>
</tr>
<tr>
<td>Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>186,746</td>
<td>197,303</td>
<td>193,251</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>(303)</td>
<td>(20,874)</td>
<td>(10,900)</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>(6,551)</td>
<td>(4,758)</td>
<td>(4,122)</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>(3,364)</td>
<td>(3,036)</td>
<td>(1,865)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>(10,551)</td>
<td>(232)</td>
<td>(11,703)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>(11,153)</td>
<td>(44,346)</td>
<td>(31,947)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>12,254</td>
<td>(11,030)</td>
<td>16,013</td>
</tr>
<tr>
<td>Changes in Certain Components of Working Capital:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts Receivable, Net</td>
<td>(14,976)</td>
<td>6,242</td>
<td>(5,766)</td>
</tr>
<tr>
<td>Fuel, Materials and Supplies</td>
<td>(3,381)</td>
<td>11,822</td>
<td>(13,015)</td>
</tr>
<tr>
<td>Accounts Payable</td>
<td>67,349</td>
<td>9,176</td>
<td>29,063</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>(12,950)</td>
<td>16,159</td>
<td>2,574</td>
</tr>
<tr>
<td>Accrued Taxes, Net</td>
<td>5,075</td>
<td>26,705</td>
<td>40,897</td>
</tr>
<tr>
<td>Other Current Assets</td>
<td>(23,730)</td>
<td>(9,542)</td>
<td>21,400</td>
</tr>
<tr>
<td>Other Current Liabilities</td>
<td>(8,241)</td>
<td>19,170</td>
<td>6,738</td>
</tr>
<tr>
<td>Net Cash Flows from Operating Activities</td>
<td>413,354</td>
<td>450,847</td>
<td>416,197</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>INVESTING ACTIVITIES</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Expenditures</td>
<td>(433,014)</td>
<td>(338,097)</td>
<td>(306,559)</td>
</tr>
<tr>
<td>Change in Other Cash Deposits</td>
<td>21,460</td>
<td>(52,609)</td>
<td>(1,151)</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(807)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Acquisition of Darby Plant</td>
<td>-</td>
<td>(102,033)</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>1,576</td>
<td>1,200</td>
<td>1,827</td>
</tr>
<tr>
<td>Net Cash Flows Used for Investing Activities</td>
<td>(410,785)</td>
<td>(491,539)</td>
<td>(305,883)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FINANCING ACTIVITIES</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Issuance of Long-term Debt – Nonaffiliated</td>
<td>346,397</td>
<td>99,173</td>
<td>-</td>
</tr>
<tr>
<td>Change in Advances from Affiliates, Net</td>
<td>(20,334)</td>
<td>94,503</td>
<td>(16,913)</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Nonaffiliated</td>
<td>(204,245)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Principal Payments for Capital Lease Obligations</td>
<td>(2,936)</td>
<td>(2,914)</td>
<td>(3,022)</td>
</tr>
<tr>
<td>Dividends Paid on Common Stock</td>
<td>(122,500)</td>
<td>(150,000)</td>
<td>(90,000)</td>
</tr>
<tr>
<td>Other</td>
<td>723</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Net Cash Flows from (Used for) Financing Activities</td>
<td>(2,895)</td>
<td>40,762</td>
<td>(109,935)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SUPPLEMENTARY INFORMATION</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash Paid for Interest, Net of Capitalized Amounts</td>
<td>$78,539</td>
<td>$65,552</td>
<td>$62,806</td>
</tr>
<tr>
<td>Net Cash Paid for Income Taxes</td>
<td>113,140</td>
<td>144,101</td>
<td>92,295</td>
</tr>
<tr>
<td>Noncash Acquisitions Under Capital Leases</td>
<td>2,326</td>
<td>2,702</td>
<td>2,286</td>
</tr>
<tr>
<td>Construction Expenditures Included in Accounts Payable at December 31,</td>
<td>47,438</td>
<td>42,163</td>
<td>35,627</td>
</tr>
<tr>
<td>Noncash Assumption of Liabilities Related to Acquisition of Darby Plant</td>
<td>-</td>
<td>2,339</td>
<td>-</td>
</tr>
<tr>
<td>Revenue Refund Included in Accounts Payable at December 31,</td>
<td>44,178</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to CSPCo’s consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page H-1.

<table>
<thead>
<tr>
<th>Footnote Reference</th>
<th>Note</th>
</tr>
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<tbody>
<tr>
<td>Organization and Summary of Significant Accounting Policies</td>
<td>1</td>
</tr>
<tr>
<td>New Accounting Pronouncements and Extraordinary Item</td>
<td>2</td>
</tr>
<tr>
<td>Rate Matters</td>
<td>4</td>
</tr>
<tr>
<td>Effects of Regulation</td>
<td>5</td>
</tr>
<tr>
<td>Commitments, Guarantees and Contingencies</td>
<td>6</td>
</tr>
<tr>
<td>Acquisitions and Asset Impairment</td>
<td>7</td>
</tr>
<tr>
<td>Benefit Plans</td>
<td>8</td>
</tr>
<tr>
<td>Business Segments</td>
<td>10</td>
</tr>
<tr>
<td>Derivatives, Hedging and Fair Value Measurements</td>
<td>11</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>12</td>
</tr>
<tr>
<td>Leases</td>
<td>13</td>
</tr>
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<td>Financing Activities</td>
<td>14</td>
</tr>
<tr>
<td>Related Party Transactions</td>
<td>15</td>
</tr>
<tr>
<td>Property, Plant and Equipment</td>
<td>16</td>
</tr>
<tr>
<td>Unaudited Quarterly Financial Information</td>
<td>17</td>
</tr>
</tbody>
</table>
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets of Columbus Southern Power Company and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 8 to the consolidated financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
The management of Columbus Southern Power Company and subsidiaries (CSPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. CSPCo’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of CSPCo’s internal control over financial reporting as of December 31, 2008. In making this assessment, CSPCo used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, CSPCo’s internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of CSPCo’s registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by CSPCo’s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit CSPCo to provide only management’s report in this annual report.
As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 582,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. I&M consolidates Blackhawk Coal Company and Price River Coal Company, its wholly-owned subsidiaries. As a member of the AEP Power Pool, I&M shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. I&M also sells power at wholesale to municipalities and electric cooperatives. I&M’s River Transportation Division (RTD) provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues.

The cost of the AEP Power Pool’s generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member’s prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member’s percentage share of revenues and costs.

Under unit power agreements, I&M purchases AEGCo’s 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the AEP Power Pool. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo’s Rockport Plant capacity to KPCo through 2022. Therefore, I&M purchases 910 MW of AEGCo’s 50% share of Rockport Plant capacity.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies’ and AEP West companies’ allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, 2006 net income and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on I&M’s behalf. I&M shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. I&M shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.
To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Results of Operations

2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008

<table>
<thead>
<tr>
<th>Net Income (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year Ended December 31, 2007</td>
</tr>
<tr>
<td>Year Ended December 31, 2008</td>
</tr>
</tbody>
</table>

Net Income decreased $5 million to $132 million in 2008. The key drivers of the decrease were an $8 million decrease in Gross Margin and a $6 million increase in Operating Expenses and Other, partially offset by a $9 million decrease in Income Tax Expense.

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

- Retail Margins decreased $52 million primarily due to the December 2008 $33 million provision for refund of off-system sales margins as ordered by the FERC related to the SIA and lower usage by industrial customers due to the economic slowdown in the second half of 2008. See “Allocation of Off-system Sales Margins” section of Note 4. An increase in capacity settlement revenues of $13 million under the Interconnection Agreement reflecting MLR changes was offset by increased cost for PJM’s revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007.
- FERC Municipals and Cooperatives margins increased $6 million due to higher revenue under new formula rate contracts signed in 2007.
- Margins from Off-system Sales decreased $6 million primarily due to lower trading margins, partially offset by higher physical sales margins driven by higher prices.
- Other revenues increased $45 million primarily due to an increase in RTD revenues of $48 million for barge services, partially offset by a decrease in gains on allowance sales. RTD’s related expenses which offset the RTD revenue increase are included in Other Operation on the Consolidated Statements of Income resulting in earning only a return approved under regulatory order.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $39 million primarily due to a $48 million increase in operation and maintenance expenses for RTD caused by increased barging activity and increased cost of fuel and a $10 million increase in distribution expense for a December 2008 ice storm. The increases were partially offset by I&M’s $14 million allocated share of a settlement agreement in 2007 regarding alleged violations of the NSR provisions of the CAA and a $6 million decrease in accretion expense. See “Federal EPA Complaint and Notice of Violation” section of Note 6.
- Depreciation and Amortization decreased $49 million primarily due to reduced depreciation rates reflecting longer estimated lives for Cook and Tanners Creek Plants. Depreciation rates were reduced for the Indiana jurisdiction in June 2007 and the FERC and Michigan jurisdictions in October 2007.
- Interest Expense increased $10 million primarily due to interest expense of $15 million related to the December 2008 provision for refund on off-system sales margins in accordance with the FERC’s order related to the SIA, partially offset by a decrease in other interest expense related to tax adjustments. See “Allocation of Off-system Sales Margins” section of Note 4.
- Income Tax Expense decreased $9 million primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis, partially offset by a decrease in amortization of investment tax credits.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. Management’s current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. In January 2009, I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the fuel cost forecast period of April through September 2009. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncement

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.
Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section for disclosures about risk management activities.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which I&M’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on I&M’s debt portfolio is $6.7 million.
### INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
#### CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

#### REVENUES
<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Generation, Transmission and Distribution</td>
<td>$1,727,769</td>
<td>$1,708,198</td>
<td>$1,601,135</td>
</tr>
<tr>
<td>Sales to AEP Affiliates</td>
<td>302,741</td>
<td>248,414</td>
<td>291,033</td>
</tr>
<tr>
<td>Other – Affiliated</td>
<td>116,747</td>
<td>59,213</td>
<td>52,598</td>
</tr>
<tr>
<td>Other – Nonaffiliated</td>
<td>19,102</td>
<td>27,367</td>
<td>32,181</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>2,166,359</strong></td>
<td><strong>2,043,192</strong></td>
<td><strong>1,976,947</strong></td>
</tr>
</tbody>
</table>

#### EXPENSES
<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel and Other Consumables Used for Electric Generation</td>
<td>436,078</td>
<td>374,256</td>
<td>373,741</td>
</tr>
<tr>
<td>Purchased Electricity for Resale</td>
<td>116,958</td>
<td>89,295</td>
<td>62,098</td>
</tr>
<tr>
<td>Purchased Electricity from AEP Affiliates</td>
<td>384,182</td>
<td>341,981</td>
<td>343,156</td>
</tr>
<tr>
<td>Other Operation</td>
<td>527,669</td>
<td>492,309</td>
<td>472,404</td>
</tr>
<tr>
<td>Maintenance</td>
<td>219,630</td>
<td>216,598</td>
<td>190,866</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>127,406</td>
<td>176,611</td>
<td>208,633</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>78,338</td>
<td>74,976</td>
<td>73,858</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>1,890,261</strong></td>
<td><strong>1,766,026</strong></td>
<td><strong>1,724,756</strong></td>
</tr>
</tbody>
</table>

**OPERATING INCOME**

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>276,098</strong></td>
<td><strong>277,166</strong></td>
<td><strong>252,191</strong></td>
<td></td>
</tr>
</tbody>
</table>

**Other Income (Expense):**

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest Income</td>
<td>2,921</td>
<td>2,740</td>
<td>9,868</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>965</td>
<td>4,522</td>
<td>7,937</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(89,851)</td>
<td>(80,034)</td>
<td>(72,723)</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>190,133</strong></td>
<td><strong>204,394</strong></td>
<td><strong>197,273</strong></td>
</tr>
</tbody>
</table>

**INCOME BEFORE INCOME TAX EXPENSE**

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax Expense</td>
<td>58,258</td>
<td>67,499</td>
<td>76,105</td>
</tr>
<tr>
<td><strong>NET INCOME</strong></td>
<td><strong>131,875</strong></td>
<td><strong>136,895</strong></td>
<td><strong>121,168</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preferred Stock Dividend Requirements</td>
<td>339</td>
<td>339</td>
<td>339</td>
</tr>
</tbody>
</table>

**EARNINGS APPLICABLE TO COMMON STOCK**

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>$131,536</td>
<td>$136,556</td>
<td>$120,829</td>
<td></td>
</tr>
</tbody>
</table>

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
## Indiana Michigan Power Company and Subsidiaries

**Consolidated Statements of Changes in Common Shareholder’s Equity and Comprehensive Income (Loss)**

For the Years Ended December 31, 2008, 2007 and 2006

(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Common Stock</th>
<th>Paid-in Capital</th>
<th>Retained Earnings</th>
<th>Accumulated Other Comprehensive Income (Loss)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DECEMBER 31, 2005</strong></td>
<td>$56,584</td>
<td>$861,290</td>
<td>$305,787</td>
<td>$(3,569)</td>
<td>$1,220,092</td>
</tr>
<tr>
<td>Common Stock Dividends</td>
<td>(40,000)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Preferred Stock Dividends</td>
<td>(339)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$1,179,753</td>
</tr>
</tbody>
</table>

**COMPREHENSIVE INCOME**

Other Comprehensive Loss, Net of Taxes:
- Cash Flow Hedges, Net of Tax of $2,959
- Minimum Pension Liability, Net of Tax of $70

**NET INCOME**

121,168

**TOTAL COMPREHENSIVE INCOME**

115,544

Minimum Pension Liability Elimination, Net of Tax of $124

231

SFAS 158 Adoption, Net of Tax of $3,278

(6,089)

**DECEMBER 31, 2006**

56,584

861,290

386,616

(15,051)

1,289,439

FIN 48 Adoption, Net of Tax

327

Common Stock Dividends

(40,000)

Preferred Stock Dividends

(339)

Gain on Reacquired Preferred Stock

1

**TOTAL**

1,249,428

**COMPREHENSIVE INCOME**

Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $1,717
- Pension and OPEB Funded Status, Net of Tax of $1,381

**NET INCOME**

136,895

**TOTAL COMPREHENSIVE INCOME**

136,271

**DECEMBER 31, 2007**

56,584

861,291

483,499

(15,675)

1,385,699

EITF 06-10 Adoption, Net of Tax of $753

(1,398)

Common Stock Dividends

(75,000)

Preferred Stock Dividends

(339)

**TOTAL**

1,308,962

**COMPREHENSIVE INCOME**

Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $1,676
- Amortization of Pension and OPEB Deferred Costs, Net of Tax of $237
- Pension and OPEB Funded Status, Net of Tax of $5,154

**NET INCOME**

131,875

**TOTAL COMPREHENSIVE INCOME**

125,856

**DECEMBER 31, 2008**

$56,584

$861,291

$538,637

$(21,694)

$1,434,818

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
### INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
### CONSOLIDATED BALANCE SHEETS
### ASSETS
#### December 31, 2008 and 2007
(in thousands)

<table>
<thead>
<tr>
<th>CURRENT ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$ 728</td>
<td>$ 1,139</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customers</td>
<td>70,432</td>
<td>70,995</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>94,205</td>
<td>92,018</td>
</tr>
<tr>
<td>Accrued Unbilled Revenues</td>
<td>19,260</td>
<td>16,207</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>1,010</td>
<td>1,335</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts</td>
<td>(3,310)</td>
<td>(2,711)</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>181,597</td>
<td>177,844</td>
</tr>
<tr>
<td>Fuel</td>
<td>67,138</td>
<td>61,342</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>150,644</td>
<td>141,384</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>35,012</td>
<td>32,365</td>
</tr>
<tr>
<td>Regulatory Asset for Under-Recovered Fuel Costs</td>
<td>33,066</td>
<td>844</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>66,733</td>
<td>14,685</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$ 534,918</td>
<td>$ 429,603</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PROPERTY, PLANT AND EQUIPMENT</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>3,534,188</td>
<td>3,529,524</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,115,762</td>
<td>1,078,575</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,297,482</td>
<td>1,196,397</td>
</tr>
<tr>
<td>Other (including nuclear fuel and coal mining)</td>
<td>703,287</td>
<td>626,390</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>249,020</td>
<td>122,296</td>
</tr>
<tr>
<td>Total</td>
<td>6,899,739</td>
<td>6,553,182</td>
</tr>
<tr>
<td>Accumulated Depreciation, Depletion and Amortization</td>
<td>3,019,206</td>
<td>2,998,416</td>
</tr>
<tr>
<td>TOTAL - NET</td>
<td>$ 3,880,533</td>
<td>$ 3,554,766</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OTHER NONCURRENT ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Assets</td>
<td>455,132</td>
<td>246,435</td>
</tr>
<tr>
<td>Spent Nuclear Fuel and Decommissioning Trusts</td>
<td>1,259,533</td>
<td>1,346,798</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>27,616</td>
<td>40,227</td>
</tr>
<tr>
<td>Deferred Charges and Other</td>
<td>86,193</td>
<td>128,623</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$ 1,828,474</td>
<td>$ 1,762,083</td>
</tr>
</tbody>
</table>

**TOTAL ASSETS**

<table>
<thead>
<tr>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 6,243,925</td>
<td>$ 5,746,452</td>
</tr>
</tbody>
</table>

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS’ EQUITY
December 31, 2008 and 2007

<table>
<thead>
<tr>
<th>CURRENT LIABILITIES</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates</td>
<td>$476,036</td>
<td>$45,064</td>
</tr>
<tr>
<td>Accounts Payable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>194,211</td>
<td>184,435</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>117,589</td>
<td>61,749</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year – Nonaffiliated</td>
<td>-</td>
<td>145,000</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>16,079</td>
<td>27,271</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>66,363</td>
<td>60,995</td>
</tr>
<tr>
<td>Obligations Under Capital Leases</td>
<td>43,512</td>
<td>43,382</td>
</tr>
<tr>
<td>Other</td>
<td>167,969</td>
<td>156,677</td>
</tr>
<tr>
<td>TOTAL</td>
<td>1,081,759</td>
<td>724,573</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NONCURRENT LIABILITIES</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Debt – Nonaffiliated</td>
<td>1,377,914</td>
<td>1,422,427</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>14,311</td>
<td>26,348</td>
</tr>
<tr>
<td>Regulatory Liabilities and Deferred Investment Tax Credits</td>
<td>412,264</td>
<td>321,716</td>
</tr>
<tr>
<td>Asset Retirement Obligations</td>
<td>902,920</td>
<td>852,646</td>
</tr>
<tr>
<td>Deferred Credits and Other</td>
<td>355,463</td>
<td>215,617</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,719,268</td>
<td>3,628,100</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>TOTAL LIABILITIES</th>
<th>4,801,027</th>
<th>4,352,673</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>8,080</td>
<td>8,080</td>
</tr>
<tr>
<td>Commitments and Contingencies (Note 6)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>COMMON SHAREHOLDER’S EQUITY</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Stock – No Par Value:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Authorized – 2,500,000 Shares</td>
<td>56,584</td>
<td>56,584</td>
</tr>
<tr>
<td>Outstanding – 1,400,000 Shares</td>
<td>861,291</td>
<td>861,291</td>
</tr>
<tr>
<td>Paid-in Capital</td>
<td>538,637</td>
<td>483,499</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>(21,694)</td>
<td>(15,675)</td>
</tr>
<tr>
<td>Accumulated Other Comprehensive Income (Loss)</td>
<td>1,434,818</td>
<td>1,385,699</td>
</tr>
<tr>
<td>TOTAL</td>
<td>6,243,925</td>
<td>5,746,452</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
# INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF CASH FLOWS
### For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th>OPERATING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$ 131,875</td>
<td>$ 136,895</td>
<td>$ 121,168</td>
</tr>
<tr>
<td>Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>127,406</td>
<td>176,611</td>
<td>208,633</td>
</tr>
<tr>
<td>Accretion of Asset Retirement Obligations</td>
<td>21,178</td>
<td>26,954</td>
<td>25,938</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>57,879</td>
<td>4,177</td>
<td>13,626</td>
</tr>
<tr>
<td>Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net</td>
<td>8,925</td>
<td>12,974</td>
<td>(23,893)</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>(965)</td>
<td>(4,522)</td>
<td>(7,937)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>(10,482)</td>
<td>1,452</td>
<td>(12,478)</td>
</tr>
<tr>
<td>Amortization of Nuclear Fuel</td>
<td>87,574</td>
<td>65,166</td>
<td>50,313</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>(9,533)</td>
<td>(4,211)</td>
<td>12,746</td>
</tr>
<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>45,073</td>
<td>33,766</td>
<td>884</td>
</tr>
<tr>
<td>Changes in Certain Components of Working Capital:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts Receivable, Net</td>
<td>(3,753)</td>
<td>6,427</td>
<td>(2,154)</td>
</tr>
<tr>
<td>Fuel, Materials and Supplies</td>
<td>(7,822)</td>
<td>2,736</td>
<td>(50,689)</td>
</tr>
<tr>
<td>Accounts Payable</td>
<td>90,041</td>
<td>(31,547)</td>
<td>37,651</td>
</tr>
<tr>
<td>Accrued Taxes, Net</td>
<td>6,238</td>
<td>28,815</td>
<td>27,553</td>
</tr>
<tr>
<td>Fuel Over/Under Recovery, Net</td>
<td>(35,688)</td>
<td>5,480</td>
<td>3,005</td>
</tr>
<tr>
<td>Other Current Assets</td>
<td>(31,979)</td>
<td>2,791</td>
<td>8,956</td>
</tr>
<tr>
<td>Other Current Liabilities</td>
<td>15,351</td>
<td>(9,966)</td>
<td>12,305</td>
</tr>
<tr>
<td>Net Cash Flows from Operating Activities</td>
<td>491,363</td>
<td>453,998</td>
<td>425,627</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>INVESTING ACTIVITIES</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Expenditures</td>
<td>(352,335)</td>
<td>(294,687)</td>
<td>(325,390)</td>
</tr>
<tr>
<td>Purchases of Investment Securities</td>
<td>(803,664)</td>
<td>(776,844)</td>
<td>(691,956)</td>
</tr>
<tr>
<td>Sales of Investment Securities</td>
<td>732,475</td>
<td>695,918</td>
<td>630,555</td>
</tr>
<tr>
<td>Acquisitions of Nuclear Fuel</td>
<td>(192,299)</td>
<td>(74,304)</td>
<td>(89,100)</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(1,181)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>4,663</td>
<td>2,849</td>
<td>4,906</td>
</tr>
<tr>
<td>Other</td>
<td>160</td>
<td>5</td>
<td>1,552</td>
</tr>
<tr>
<td>Net Cash Flows Used for Investing Activities</td>
<td>(612,181)</td>
<td>(447,063)</td>
<td>(469,433)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FINANCING ACTIVITIES</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Issuance of Long-term Debt – Nonaffiliated</td>
<td>115,269</td>
<td>-</td>
<td>443,743</td>
</tr>
<tr>
<td>Change in Advances from Affiliates, Net</td>
<td>430,972</td>
<td>(46,109)</td>
<td>(2,529)</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Nonaffiliated</td>
<td>(312,000)</td>
<td>-</td>
<td>(350,000)</td>
</tr>
<tr>
<td>Retirement of Cumulative Preferred Stock</td>
<td>-</td>
<td>(2)</td>
<td>(1)</td>
</tr>
<tr>
<td>Proceeds from Nuclear Fuel Sale/Leaseback</td>
<td>-</td>
<td>85,000</td>
<td>-</td>
</tr>
<tr>
<td>Principal Payments for Capital Lease Obligations</td>
<td>(39,427)</td>
<td>(5,715)</td>
<td>(6,553)</td>
</tr>
<tr>
<td>Dividends Paid on Common Stock</td>
<td>(75,000)</td>
<td>(40,000)</td>
<td>(40,000)</td>
</tr>
<tr>
<td>Dividends Paid on Cumulative Preferred Stock</td>
<td>(339)</td>
<td>(339)</td>
<td>(339)</td>
</tr>
<tr>
<td>Other</td>
<td>932</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Net Cash Flows from (Used for) Financing Activities</td>
<td>120,407</td>
<td>(7,165)</td>
<td>44,321</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SUPPLEMENTARY INFORMATION</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Increase (Decrease) in Cash and Cash Equivalents</td>
<td>(411)</td>
<td>(230)</td>
<td>515</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
<td>1,139</td>
<td>1,369</td>
<td>854</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
<td>$ 728</td>
<td>$ 1,139</td>
<td>$ 1,369</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
The notes to I&M’s consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page H-1.

<table>
<thead>
<tr>
<th>Footnote Reference</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Note 1</td>
<td>Organization and Summary of Significant Accounting Policies</td>
</tr>
<tr>
<td>Note 2</td>
<td>New Accounting Pronouncements and Extraordinary Item</td>
</tr>
<tr>
<td>Note 4</td>
<td>Rate Matters</td>
</tr>
<tr>
<td>Note 5</td>
<td>Effects of Regulation</td>
</tr>
<tr>
<td>Note 6</td>
<td>Commitments, Guarantees and Contingencies</td>
</tr>
<tr>
<td>Note 8</td>
<td>Benefit Plans</td>
</tr>
<tr>
<td>Note 9</td>
<td>Nuclear</td>
</tr>
<tr>
<td>Note 10</td>
<td>Business Segments</td>
</tr>
<tr>
<td>Note 11</td>
<td>Derivatives, Hedging and Fair Value Measurements</td>
</tr>
<tr>
<td>Note 12</td>
<td>Income Taxes</td>
</tr>
<tr>
<td>Note 13</td>
<td>Leases</td>
</tr>
<tr>
<td>Note 14</td>
<td>Financing Activities</td>
</tr>
<tr>
<td>Note 15</td>
<td>Related Party Transactions</td>
</tr>
<tr>
<td>Note 16</td>
<td>Property, Plant and Equipment</td>
</tr>
<tr>
<td>Note 17</td>
<td>Unaudited Quarterly Financial Information</td>
</tr>
</tbody>
</table>
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 8 to the consolidated financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
The management of Indiana Michigan Power Company and subsidiaries (I&M) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. I&M’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of I&M’s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, I&M’s internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of I&M’s registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by I&M’s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit I&M to provide only management’s report in this annual report.
### OHIO POWER COMPANY CONSOLIDATED
### SELECTED CONSOLIDATED FINANCIAL DATA
### (in thousands)

#### STATEMENTS OF INCOME DATA

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenues</td>
<td>$3,096,934</td>
<td>$2,814,212</td>
<td>$2,724,875</td>
<td>$2,634,549</td>
<td>$2,372,725</td>
</tr>
<tr>
<td>Operating Income</td>
<td>$495,050</td>
<td>$526,352</td>
<td>$425,291</td>
<td>$425,487</td>
<td>$419,539</td>
</tr>
<tr>
<td>Income Before Cumulative Effect of Accounting Changes</td>
<td>$231,123</td>
<td>$268,564</td>
<td>$228,643</td>
<td>$250,419</td>
<td>$210,116</td>
</tr>
<tr>
<td>Cumulative Effect of Accounting Changes, Net of Tax</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(4,575)</td>
<td>-</td>
</tr>
<tr>
<td>Net Income</td>
<td>$231,123</td>
<td>$268,564</td>
<td>$228,643</td>
<td>$245,844</td>
<td>$210,116</td>
</tr>
</tbody>
</table>

#### BALANCE SHEETS DATA

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Property, Plant and Equipment</td>
<td>$9,788,862</td>
<td>$9,140,357</td>
<td>$8,405,645</td>
<td>$7,523,288</td>
<td>$6,858,771</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>3,122,989</td>
<td>2,967,285</td>
<td>2,836,584</td>
<td>2,738,899</td>
<td>2,633,203</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>$6,665,873</td>
<td>$6,173,072</td>
<td>$5,569,061</td>
<td>$4,784,389</td>
<td>$4,225,568</td>
</tr>
<tr>
<td>Total Assets</td>
<td>$8,003,826</td>
<td>$7,338,429</td>
<td>$6,807,528</td>
<td>$6,288,869</td>
<td>$5,585,092</td>
</tr>
<tr>
<td>Common Shareholder’s Equity</td>
<td>$2,421,945</td>
<td>$2,291,017</td>
<td>$2,008,342</td>
<td>$1,767,947</td>
<td>$1,473,838</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>$16,627</td>
<td>$16,627</td>
<td>$16,630</td>
<td>$16,639</td>
<td>$16,641</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Subject to Mandatory Redemption</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$5,000</td>
</tr>
<tr>
<td>Long-term Debt (b)</td>
<td>$3,039,376</td>
<td>$2,849,598</td>
<td>$2,401,741</td>
<td>$2,199,670</td>
<td>$2,011,060</td>
</tr>
<tr>
<td>Obligations Under Capital Leases (b)</td>
<td>$26,466</td>
<td>$29,077</td>
<td>$34,966</td>
<td>$39,924</td>
<td>$40,733</td>
</tr>
</tbody>
</table>

(a) Includes reclassification of assets due to FSP FIN 39-1 adoption effective in 2008. See “FSP FIN 39-1” section of Note 2.
(b) Includes portion due within one year.
OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT’S FINANCIAL DISCUSSION AND ANALYSIS

As a public utility, OPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. OPCo consolidates JMG Funding LP, a variable interest entity. As a member of the AEP Power Pool, OPCo shares in the revenues and the costs of the AEP Power Pool’s sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool’s generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member’s prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member’s percentage share of revenues and costs.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies’ and AEP West companies’ allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, 2006 net income and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on OPCo’s behalf. OPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. OPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints of operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

OPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.
Results of Operations

2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008

Net Income
(in millions)

<table>
<thead>
<tr>
<th>Year Ended December 31, 2007</th>
<th>$ 269</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Changes in Gross Margin:</strong></td>
<td></td>
</tr>
<tr>
<td>Retail Margins</td>
<td>(99)</td>
</tr>
<tr>
<td>Off-system Sales</td>
<td>10</td>
</tr>
<tr>
<td>Transmission Revenues</td>
<td>1</td>
</tr>
<tr>
<td>Other</td>
<td>21</td>
</tr>
<tr>
<td><strong>Total Change in Gross Margin</strong></td>
<td>(67)</td>
</tr>
<tr>
<td><strong>Changes in Operating Expenses and Other:</strong></td>
<td></td>
</tr>
<tr>
<td>Other Operation and Maintenance</td>
<td>(31)</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>66</td>
</tr>
<tr>
<td>Other Income</td>
<td>6</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>2</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(48)</td>
</tr>
<tr>
<td><strong>Total Change in Operating Expenses and Other</strong></td>
<td>(5)</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>34</td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td>$ 231</td>
</tr>
</tbody>
</table>

Net Income decreased $38 million to $231 million in 2008. The key drivers of the decrease were a $67 million decrease in Gross Margin and a $5 million increase in Operating Expenses and Other, partially offset by a $34 million decrease in Income Tax Expense.

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

- Retail Margins decreased $99 million primarily due to the following:
  - A $148 million increase in fuel and consumables expenses. OPCo has applied for an active fuel clause in its Ohio ESP to be effective January 1, 2009. See “Ohio Electric Security Plan Filings” section of Note 4.
  - A $42 million decrease due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $24 million decrease in industrial sales due to the economic slowdown in the second half of 2008.
- These decreases were partially offset by:
  - A $61 million increase related to a net increase in rates implemented.
  - A $40 million net increase related to coal contract amendments in 2008.
  - A $31 million increase in capacity settlements under the Interconnection Agreement related to an increase in an affiliate’s peak.
  - A $21 million increase primarily related to increased usage by Ormet, a major industrial customer.

- Margins from Off-system Sales increased $10 million primarily due to increased physical sales margins driven by higher prices.

- Other revenues increased $21 million primarily due to net gains on the sale of emission allowances.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $31 million primarily due to:
  - A $27 million increase in recoverable PJM expenses.
  - A $15 million increase in recoverable customer account expenses related to the Universal Service Fund for customers who qualify for payment assistance.
  - A $5 million increase in transmission expenses related to the AEP Transmission Equalization Agreement.
  - A $4 million increase in maintenance expenses from planned and forced outages at various plants.
These increases were partially offset by:
  - A $17 million decrease resulting from a settlement agreement in the third quarter of 2007 related to alleged violations of the NSR provisions of the CAA. The $17 million represents OPCo’s allocation of the settlement. See “Federal EPA Complaint and Notice of Violation” section of Note 6.
  - A $10 million decrease in removal expenses related to planned outages at various plants during 2007, partially offset by planned outages at the Amos Plant during 2008.
- Depreciation and Amortization decreased $66 million primarily due to:
  - A $70 million decrease in amortization as a result of completion of amortization of regulatory assets in December 2007.
  - A $15 million decrease due to the amortization of regulatory credits related to energy sales to Ormet at below market rates.
  - A $6 million decrease due to the amortization of IGCC pre-construction costs, which ended in the second quarter of 2007. The amortization of IGCC pre-construction costs was offset by a corresponding increase in Retail Margins in 2007.
These decreases were partially offset by:
- Interest Expense increased $48 million due to interest expense of $20 million related to the December 2008 provision for refund of off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4. The increase is also a result of a decrease in the debt component of AFUDC as a result of Mitchell Plant and Cardinal Plant environmental improvements placed in service, the issuance of additional long-term debt and higher interest rates on variable rate debt.
- Income Tax Expense decreased $34 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments.
2007 Compared to 2006

Reconciliation of Year Ended December 31, 2006 to Year Ended December 31, 2007

Net Income (in millions)

Year Ended December 31, 2006 $229

Changes in Gross Margin:

Retail Margins 157
Off-system Sales (28)
Transmission Revenues (3)
Other (19)
Total Change in Gross Margin 107

Changes in Operating Expenses and Other:

Other Operation and Maintenance 13
Depreciation and Amortization (18)
Taxes Other Than Income Taxes (1)
Other Income (1)
Interest Expense (30)
Total Change in Operating Expenses and Other (37)

Income Tax Expense (30)

Year Ended December 31, 2007 $269

Net Income increased $40 million to $269 million in 2007. The key drivers of the increase was a $107 million increase in Gross Margin, partially offset by a $37 million increase in Operating Expenses and Other and a $30 million increase in Income Tax Expense.

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

- Retail Margins increased $157 million primarily due to the following:
  - A $44 million increase in capacity settlements under the Interconnection Agreement related to certain affiliates’ peaks and the June 2006 expiration of OPCo’s supplemental capacity and energy obligation to Buckeye Power, Inc. under the Cardinal Station Agreement.
  - A $40 million increase in rate revenues primarily related to a $36 million increase in OPCo’s RSP and a $6 million increase related to rate recovery of storm costs. The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance.
  - A $43 million increase in industrial revenue due to the addition of Ormet, a major industrial customer, effective January 1, 2007. See “Ormet” section of Note 4.
  - An $18 million increase in residential and commercial revenue primarily due to a 33% increase in cooling degree days and a 22% increase in heating degree days.

The increases were partially offset by:

- A $23 million decrease due to PJM’s revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007.

- Margins from Off-system Sales decreased $28 million primarily due to lower physical sales of which $30 million related to OPCo’s purchase power and sale agreement with Dow Chemical Company (Dow) which ended in November 2006. The decreased physical sales were partially offset by higher trading margins. See “Plaquemine Cogeneration Facility” section of the “Other” section below for additional discussion of Dow.

- Other revenues decreased $19 million primarily due to an $8 million decrease in gains on sales of emission allowances and a $7 million decrease related to the April 2006 expiration of an obligation to sell supplemental capacity and energy to Buckeye Power, Inc. under the Cardinal Station Agreement.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $13 million primarily due to the following:
  - A $30 million decrease in maintenance and rental expenses related to OPCo’s purchase power and sale agreement with Dow which ended in November 2006. This decrease was offset by a corresponding decrease in margins from Off-system Sales. See “Plaquemine Cogeneration Facility” section of the “Other” section below for additional discussion of Dow.
  - A $15 million decrease in maintenance from planned and forced outages at the Gavin, Kammer, Mitchell and Muskingum River Plants related to boiler tube inspections in 2006.
  
  These decreases were partially offset by:
  - A $17 million increase resulting from a settlement agreement in the third quarter of 2007 related to alleged violations of the NSR provisions of the CAA. The $17 million represents OPCo’s allocation of the settlement. See “Federal EPA Complaint and Notice of Violation” section of Note 6.
  - A $10 million increase due to adjustments in 2006 of liabilities related to sold coal companies.
  - A $7 million increase in overhead line expenses primarily due to the 2006 recognition of a regulatory asset related to PUCO orders regarding distribution service reliability and restoration costs and the amortization of deferred storm expenses recovered through a cost-recovery rider. The increase in the amortization of deferred storm expenses was offset by a corresponding increase in Retail Margins.

- Depreciation and Amortization increased $18 million primarily due to a $25 million increase in depreciation related to environmental improvements placed in service at the Mitchell Plant. These increases were partially offset by a $7 million decrease from the amortization of a regulatory liability related to Ormet. See “Ormet” section of Note 4.

- Interest Expense increased $30 million primarily due to increases in long-term borrowings.
- Income Tax Expense increased $30 million primarily due to an increase in pretax book income and state income taxes.

Financial Condition

Credit Ratings

Current ratings for OPCo are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Moody’s</th>
<th>S&amp;P</th>
<th>Fitch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Senior Unsecured Debt</td>
<td>A3</td>
<td>BBB</td>
<td>BBB+</td>
</tr>
</tbody>
</table>

S&P and Fitch currently have OPCo on stable outlook while Moody’s has OPCo on negative outlook. In January 2009, Moody’s placed OPCo on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries. If OPCo receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Liquidity

In 2008, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting OPCo’s access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on OPCo since it relies on continuing access to capital to fund operations and capital expenditures.

OPCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. OPCo has $78 million of Notes Payable that will mature in 2009. To the extent refinancing is unavailable due to challenging credit markets in 2009, OPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of liquidity.
Cash Flow

Cash flows for 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th></th>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008 (in thousands)</td>
</tr>
<tr>
<td></td>
<td>2007 (in thousands)</td>
</tr>
<tr>
<td></td>
<td>2006 (in thousands)</td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at Beginning of Period</strong></td>
<td>$ 6,666</td>
</tr>
<tr>
<td>Operating Activities</td>
<td>485,421</td>
</tr>
<tr>
<td>Investing Activities</td>
<td>(701,789)</td>
</tr>
<tr>
<td>Financing Activities</td>
<td>222,381</td>
</tr>
<tr>
<td><strong>Net Increase (Decrease) in Cash and Cash Equivalents</strong></td>
<td>6,013</td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at End of Period</strong></td>
<td>$ 12,679</td>
</tr>
</tbody>
</table>

**Operating Activities**

Net Cash Flows from Operating Activities were $485 million in 2008. OPCo produced Net Income of $231 million during the period and a noncash expense item of $274 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital and changes in the future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. Accounts Payable had a $127 million inflow due to increases in tonnage and prices per ton related to fuel and consumable purchases and also included OPCo’s December 2008 provision for refund of $62 million to be paid to the AEP West companies as part of the FERC’s recent order on the SIA. Fuel, Materials and Supplies had an $89 million outflow due to price increases.

Net Cash Flows from Operating Activities were $573 million in 2007. OPCo produced Net Income of $269 million during the period and a noncash expense item of $340 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items, including a $55 million outflow in Accounts Receivable, Net. Accounts Receivable, Net increased primarily due to an increase in heating degree days and timing differences of payments from customers.

Net Cash Flows from Operating Activities were $626 million in 2006. OPCo produced Net Income of $229 million during the period and a noncash expense item of $322 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items, including a $116 million inflow in Accounts Receivable, Net. Accounts Receivable, Net decreased due to the collection of receivables related to power sales to affiliates, settled litigation and emission allowances.

**Investing Activities**

Net Cash Flows Used for Investing Activities in 2008, 2007 and 2006 were $702 million, $924 million and $986 million, respectively, primarily due to Construction Expenditures for environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and flue gas desulfurization projects at the Cardinal and Mitchell Plants. In 2008, environmental upgrades were completed for Unit 1 at the Cardinal Plant. In 2007, environmental upgrades were completed for Units 1 and 2 at the Mitchell Plant.
Financing Activities

Net Cash Flows from Financing Activities were $222 million in 2008. OPCo issued $244 million of Pollution Control Bonds and $250 million of Senior Unsecured Notes. These increases were partially offset by the retirement of $250 million of Pollution Control Bonds, $37 million of Senior Unsecured Notes and $18 million of Notes Payable – Nonaffiliated.

Net Cash Flows from Financing Activities were $356 million in 2007. OPCo issued $400 million of Senior Unsecured Notes and $65 million of Pollution Control Bonds. OPCo had a net decrease of $80 million in borrowings from the Utility Money Pool.

Net Cash Flows from Financing Activities were $360 million in 2006. OPCo issued $350 million of Senior Unsecured Notes and $65 million of Pollution Control Bonds. OPCo received a capital contribution from Parent of $70 million. These amounts were partially offset by a $200 million retirement of affiliated notes payable.
Summary Obligation Information

OPCo’s contractual cash obligations include amounts reported on OPCo’s Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes OPCo’s contractual cash obligations at December 31, 2008:

### Payments Due by Period (in millions)

<table>
<thead>
<tr>
<th>Contractual Cash Obligations</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates (a)</td>
<td>$ 133.9</td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 133.9</td>
</tr>
<tr>
<td>Interest on Fixed Rate Portion of Long-term Debt (b)</td>
<td>$133.5</td>
<td>$251.9</td>
<td>$234.5</td>
<td>$1,117.8</td>
<td>$1,737.7</td>
</tr>
<tr>
<td>Fixed Rate Portion of Long-term Debt (c)</td>
<td>$77.5</td>
<td>$279.5</td>
<td>$500.0</td>
<td>$1,404.1</td>
<td>$2,261.1</td>
</tr>
<tr>
<td>Variable Rate Portion of Long-term Debt (d)</td>
<td>$ -</td>
<td>$400.0</td>
<td>$ -</td>
<td>$383.0</td>
<td>$783.0</td>
</tr>
<tr>
<td>Capital Lease Obligations (e)</td>
<td>$6.1</td>
<td>$8.7</td>
<td>$4.1</td>
<td>$17.6</td>
<td>$36.5</td>
</tr>
<tr>
<td>Noncancelable Operating Leases (e)</td>
<td>$26.7</td>
<td>$79.1</td>
<td>$30.1</td>
<td>$74.9</td>
<td>$210.8</td>
</tr>
<tr>
<td>Fuel Purchase Contracts (f)</td>
<td>$1,253.2</td>
<td>$1,576.7</td>
<td>$1,032.1</td>
<td>$3,157.7</td>
<td>$7,019.7</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (g)</td>
<td>$1.9</td>
<td>$5.8</td>
<td>$1.1</td>
<td>$ -</td>
<td>$8.8</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (h)</td>
<td>$19.4</td>
<td>$29.1</td>
<td>$43.7</td>
<td>$ -</td>
<td>$92.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$1,652.2</strong></td>
<td><strong>$2,630.8</strong></td>
<td><strong>$1,845.6</strong></td>
<td><strong>$6,155.1</strong></td>
<td><strong>$12,283.7</strong></td>
</tr>
</tbody>
</table>

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 14. Represents principal only excluding interest.
(d) See Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.85% and 13.0% at December 31, 2008.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

OPCo’s FIN 48 liabilities of $22 million are not included above because OPCo cannot reasonably estimate the cash flows by period.

AEP’s minimum pension funding requirements are not included in the above table. As of December 31, 2008, the decline in pension asset values will not require AEP to make a contribution in 2009. AEP will need to make minimum contributions to the pension plan of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

In addition to the amounts disclosed in the contractual cash obligations table above, OPCo makes additional commitments in the normal course of business. OPCo’s commitments outstanding at December 31, 2008 under these agreements are summarized in the table below:

### Amount of Commitment Expiration Per Period (in millions)

<table>
<thead>
<tr>
<th>Other Commercial Commitments</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standby Letters of Credit (a)</td>
<td>$ 166.9</td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 166.9</td>
</tr>
</tbody>
</table>

(a) OPCo has issued standby letters of credit. These letters of credit cover insurance programs, security deposits and debt service reserves. All of these letters of credit were issued in OPCo’s ordinary course of business. The maximum future payments of these letters of credit are $166.9 million maturing in June 2009. There is no recourse to third parties in the event these letters of credit are drawn. See “Letters of Credit” section of Note 6.
Other

Coal Contract Amendment

In January 2008, OPCo terminated a coal contract for deliveries of coal through 2012 and additional optional tonnage through 2017. The contracted prices were below current market prices. OPCo also entered into a new contract for reduced deliveries of comparable coal for 2009-2010, with an option for tonnage with firm pricing in 2011. Consideration received by OPCo for the significant tonnage reduction consisted of noncash consideration of approximately $70 million. A significant portion of the consideration was recognized in 2008 as a decrease to fuel expense. The remaining amount will be amortized to fuel expense as coal is delivered under the new contract in 2009-2010.

Plaquemine Cogeneration Facility

In 2000, Juniper Capital L.P. financed AEP’s nonregulated ownership interest in the Plaquemine Cogeneration Facility (the Facility) near Plaquemine, Louisiana. AEP subleased the Facility to Dow Chemical Company (Dow). As outlined in the “OPCo Indemnification Agreement with AEP Resources” section of Note 15, OPCo entered into a purchase power and sale agreement with Dow and a corresponding indemnification agreement with a nonutility subsidiary of AEP. As a result, OPCo’s net income included sales to nonaffiliated companies and offsetting maintenance expense with no effect on OPCo’s Net Income. In the fourth quarter of 2006, AEP sold the Facility to Dow. With the sale of the Facility, OPCo terminated its purchase power and sale agreement with Dow. This sale did not have an impact on OPCo’s 2006 net income. In 2006, the operation of the facility affected revenues, Fuel and Other Consumables Used for Electric Generation, Purchased Electricity for Resale, Other Operation expense and Maintenance expense by approximately $157 million, $134 million, ($7) million, $19 million and $11 million, respectively, with no effect on net income. These revenues and expenses did not recur in 2007.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect OPCo’s net income, financial condition and cash flows.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of relevant factors.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.
QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section. The following tables provide information about AEP’s risk management activities’ effect on OPCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in OPCo’s Consolidated Balance Sheet as of December 31, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet

<table>
<thead>
<tr>
<th>December 31, 2008</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MTM Risk Management Contracts</td>
</tr>
<tr>
<td>Current Assets</td>
<td>$50,440</td>
</tr>
<tr>
<td>Noncurrent Assets</td>
<td>39,840</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Assets</strong></td>
<td>90,280</td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>(28,131)</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>(24,388)</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Liabilities</strong></td>
<td>(52,519)</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Net Assets (Liabilities)</strong></td>
<td>$37,761</td>
</tr>
</tbody>
</table>

(a) See “Natural Gas Contracts with DETM” section of Note 15.
# MTM Risk Management Contract Net Assets
## Year Ended December 31, 2008
(in thousands)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total MTM Risk Management Contract Net Assets at December 31, 2007</strong></td>
<td>$30,248</td>
</tr>
<tr>
<td>(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period</td>
<td>(7,633)</td>
</tr>
<tr>
<td>Fair Value of New Contracts at Inception When Entered During the Period (a)</td>
<td>1,969</td>
</tr>
<tr>
<td>Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period</td>
<td>(64)</td>
</tr>
<tr>
<td>Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)</td>
<td>2,014</td>
</tr>
<tr>
<td>Changes in Fair Value Due to Market Fluctuations During the Period (c)</td>
<td>6,908</td>
</tr>
<tr>
<td>Changes in Fair Value Allocated to Regulated Jurisdictions (d)</td>
<td>4,319</td>
</tr>
<tr>
<td><strong>Total MTM Risk Management Contract Net Assets</strong></td>
<td>37,761</td>
</tr>
<tr>
<td>Net Cash Flow &amp; Fair Value Hedge Contracts</td>
<td>2,844</td>
</tr>
<tr>
<td>DETM Assignment (e)</td>
<td>(3,637)</td>
</tr>
<tr>
<td>Collateral Deposits</td>
<td>2,386</td>
</tr>
<tr>
<td><strong>Ending Net Risk Management Assets at December 31, 2008</strong></td>
<td>$39,354</td>
</tr>
</tbody>
</table>

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Represents the impact of applying AEP’s credit risk when measuring the fair value of derivative liabilities according to SFAS 157.

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

(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

(e) See “Natural Gas Contracts with DETM” section of Note 15.
Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(in thousands)</td>
<td></td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td></td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td></td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (d)</td>
<td></td>
</tr>
<tr>
<td>Total MTM Risk Management Contract Net Assets (Liabilities)</td>
<td></td>
</tr>
</tbody>
</table>

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

(d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contracts.

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

OPCo is exposed to market fluctuations in energy commodity prices impacting power operations. Management monitors these risks on future operations and may use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate exposure.

Management uses foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designates qualifying instruments as cash flow hedges. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on OPCo’s Consolidated Balance Sheets and the reasons for the changes from December 31, 2007 to December 31, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.
Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2008
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Power</th>
<th>Interest Rate</th>
<th>Foreign Currency</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Beginning Balance in AOCI December 31, 2007</strong></td>
<td>$(756)</td>
<td>$2,167</td>
<td>$(254)</td>
<td>$1,157</td>
</tr>
<tr>
<td><strong>Changes in Fair Value</strong></td>
<td>1,803</td>
<td>(903)</td>
<td>65</td>
<td>965</td>
</tr>
<tr>
<td><strong>Reclassifications from AOCI for Cash Flow</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hedges Settled</td>
<td>851</td>
<td>663</td>
<td>14</td>
<td>1,528</td>
</tr>
<tr>
<td><strong>Ending Balance in AOCI December 31, 2008</strong></td>
<td>$1,898</td>
<td>$1,927</td>
<td>$(175)</td>
<td>$3,650</td>
</tr>
</tbody>
</table>

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2.1 million gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2008, a near term typical change in commodity prices is not expected to have a material effect on net income, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years ended:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
</tr>
<tr>
<td>End</td>
<td>$140</td>
<td>$325</td>
</tr>
<tr>
<td>High</td>
<td>$1,284</td>
<td>$2,054</td>
</tr>
<tr>
<td>Average</td>
<td>$411</td>
<td>$490</td>
</tr>
<tr>
<td>Low</td>
<td>$131</td>
<td>$90</td>
</tr>
</tbody>
</table>

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management’s backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes OPCo’s VaR calculation is conservative.

As OPCo’s VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand its exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translated into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which OPCo’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on OPCo’s debt portfolio is $35.5 million.
# Ohio Power Company Consolidated Statements of Income

For the Years Ended December 31, 2008, 2007 and 2006

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenues</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Generation, Transmission and Distribution</td>
<td>$2,116,797</td>
<td>$2,019,632</td>
<td>$2,006,279</td>
</tr>
<tr>
<td>Sales to AEP Affiliates</td>
<td>940,468</td>
<td>757,052</td>
<td>685,343</td>
</tr>
<tr>
<td>Other - Affiliated</td>
<td>20,732</td>
<td>22,705</td>
<td>16,775</td>
</tr>
<tr>
<td>Other - Nonaffiliated</td>
<td>18,937</td>
<td>14,823</td>
<td>16,478</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>3,096,934</td>
<td>2,814,212</td>
<td>2,724,875</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expenses</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel and Other Consumables Used for Electric Generation</td>
<td>1,190,939</td>
<td>908,317</td>
<td>960,119</td>
</tr>
<tr>
<td>Purchased Electricity for Resale</td>
<td>175,429</td>
<td>123,849</td>
<td>100,958</td>
</tr>
<tr>
<td>Purchased Electricity from AEP Affiliates</td>
<td>140,686</td>
<td>125,108</td>
<td>113,651</td>
</tr>
<tr>
<td>Other Operation</td>
<td>414,945</td>
<td>388,745</td>
<td>382,573</td>
</tr>
<tr>
<td>Maintenance</td>
<td>213,431</td>
<td>208,675</td>
<td>228,151</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>273,720</td>
<td>339,817</td>
<td>321,951</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>192,734</td>
<td>193,349</td>
<td>192,178</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,601,884</td>
<td>2,287,860</td>
<td>2,299,584</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operating Income</strong></td>
<td>495,050</td>
<td>526,352</td>
<td>425,291</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Other Income (Expense):</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest Income</td>
<td>6,515</td>
<td>1,366</td>
<td>2,363</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>16,309</td>
<td>14,472</td>
<td>13,841</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>3,073</td>
<td>2,311</td>
<td>2,556</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(175,202)</td>
<td>(127,352)</td>
<td>(97,084)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Income Before Income Tax Expense</strong></td>
<td>345,745</td>
<td>417,149</td>
<td>346,967</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax Expense</td>
<td>114,622</td>
<td>148,585</td>
<td>118,324</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Income</strong></td>
<td>231,123</td>
<td>268,564</td>
<td>228,643</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preferred Stock Dividend Requirements</td>
<td>732</td>
<td>732</td>
<td>732</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Earnings Applicable to Common Stock</strong></td>
<td>$230,391</td>
<td>$267,832</td>
<td>$227,911</td>
</tr>
</tbody>
</table>

The common stock of OPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
## OHIO POWER COMPANY CONSOLIDATED

### CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2008, 2007 and 2006

(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Common Stock</th>
<th>Paid-in Capital</th>
<th>Retained Earnings</th>
<th>Accumulated Other Comprehensive Income (Loss)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DECEMBER 31, 2005</strong></td>
<td>$ 321,201</td>
<td>$ 466,637</td>
<td>$ 979,354</td>
<td>$ 755</td>
<td>$ 1,767,947</td>
</tr>
</tbody>
</table>

Capital Contribution from Parent 70,000
Preferred Stock Dividends (732)
Gain on Reacquired Preferred Stock 2

**TOTAL**

1,837,217

### COMPREHENSIVE INCOME

Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $3,504
- Minimum Pension Liability, Net of Tax of $110

**NET INCOME**

228,643

**TOTAL COMPREHENSIVE INCOME**

234,946

**DECEMBER 31, 2006**

|                | 321,201 | 536,639 | 1,207,265 | (56,763) | 2,008,342 |

FIN 48 Adoption, Net of Tax (5,380)
Preferred Stock Dividends (732)
Gain on Reacquired Preferred Stock 1

**TOTAL**

2,002,231

### COMPREHENSIVE INCOME

Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $3,287
- Pension and OPEB Funded Status, Net of Tax of $14,176

**NET INCOME**

268,564

**TOTAL COMPREHENSIVE INCOME**

288,786

**DECEMBER 31, 2007**

|                | 321,201 | 536,640 | 1,469,717 | (36,541) | 2,291,017 |

EITF 06-10 Adoption, Net of Tax of $1,004 (1,864)
SFAS 157 Adoption, Net of Tax of $152 (282)
Preferred Stock Dividends (732)

**TOTAL**

2,288,139

### COMPREHENSIVE INCOME

Other Comprehensive Income (Loss), Net of Taxes:
- Cash Flow Hedges, Net of Tax of $1,343
- Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,515
- Pension and OPEB Funded Status, Net of Tax of $55,259

**NET INCOME**

231,123

**TOTAL COMPREHENSIVE INCOME**

133,860

**DECEMBER 31, 2008**

|                | $ 321,201 | $ 536,640 | $ 1,697,962 | $ (133,858) | $ 2,421,945 |

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2008 and 2007
(in thousands)

<table>
<thead>
<tr>
<th>CURRENT ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$12,679</td>
<td>$6,666</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customers</td>
<td>91,235</td>
<td>104,783</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>118,721</td>
<td>119,560</td>
</tr>
<tr>
<td>Accrued Unbilled Revenues</td>
<td>18,239</td>
<td>26,819</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>23,393</td>
<td>1,578</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts</td>
<td>(3,586)</td>
<td>(3,396)</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>$248,002</td>
<td>$249,344</td>
</tr>
<tr>
<td>Fuel</td>
<td>186,904</td>
<td>92,874</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>107,419</td>
<td>108,447</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>53,292</td>
<td>44,236</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>56,567</td>
<td>18,300</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$664,863</td>
<td>$519,867</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PROPERTY, PLANT AND EQUIPMENT</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>6,025,277</td>
<td>5,641,537</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,111,637</td>
<td>1,068,387</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,472,906</td>
<td>1,394,988</td>
</tr>
<tr>
<td>Other</td>
<td>391,862</td>
<td>318,805</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>787,180</td>
<td>716,640</td>
</tr>
<tr>
<td>Total</td>
<td>9,788,862</td>
<td>9,140,357</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>3,122,989</td>
<td>2,967,285</td>
</tr>
<tr>
<td>TOTAL - NET</td>
<td>$6,665,873</td>
<td>$6,173,072</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OTHER NONCURRENT ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Assets</td>
<td>449,216</td>
<td>323,105</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>39,097</td>
<td>49,586</td>
</tr>
<tr>
<td>Deferred Charges and Other</td>
<td>184,777</td>
<td>272,799</td>
</tr>
<tr>
<td>TOTAL</td>
<td>673,090</td>
<td>645,490</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TOTAL ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$8,003,826</td>
<td>$7,338,429</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
## OHIO POWER COMPANY CONSOLIDATED
## CONSOLIDATED BALANCE SHEETS
## LIABILITIES AND SHAREHOLDERS’ EQUITY
## December 31, 2008 and 2007

### CURRENT LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates</td>
<td>$133,887</td>
<td>$101,548</td>
</tr>
<tr>
<td>Accounts Payable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>193,675</td>
<td>141,196</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>206,984</td>
<td>137,389</td>
</tr>
<tr>
<td>Short-term Debt – Nonaffiliated</td>
<td>-</td>
<td>701</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year – Nonaffiliated</td>
<td>77,500</td>
<td>55,188</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>29,218</td>
<td>40,548</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>24,333</td>
<td>30,613</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>187,256</td>
<td>185,011</td>
</tr>
<tr>
<td>Accrued Interest</td>
<td>44,245</td>
<td>41,880</td>
</tr>
<tr>
<td>Other</td>
<td>163,702</td>
<td>149,658</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>1,060,800</strong></td>
<td><strong>883,732</strong></td>
</tr>
</tbody>
</table>

### NONCURRENT LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Debt – Nonaffiliated</td>
<td>2,761,876</td>
<td>2,594,410</td>
</tr>
<tr>
<td>Long-term Debt – Affiliated</td>
<td>200,000</td>
<td>200,000</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>23,817</td>
<td>32,194</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>927,072</td>
<td>914,170</td>
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<tr>
<td>Regulatory Liabilities and Deferred Investment Tax Credits</td>
<td>127,788</td>
<td>160,721</td>
</tr>
<tr>
<td>Employee Benefits and Pension Obligations</td>
<td>288,106</td>
<td>81,913</td>
</tr>
<tr>
<td>Deferred Credits and Other</td>
<td>158,996</td>
<td>147,722</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>4,487,655</strong></td>
<td><strong>4,131,130</strong></td>
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</tbody>
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### TOTAL LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minority Interest</td>
<td>16,799</td>
<td>15,923</td>
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<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>16,627</td>
<td>16,627</td>
</tr>
<tr>
<td>Commitments and Contingencies (Note 6)</td>
<td></td>
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### COMMON SHAREHOLDER’S EQUITY

<table>
<thead>
<tr>
<th>Description</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
</tr>
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<tbody>
<tr>
<td>Common Stock – No Par Value:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Authorized – 40,000,000 Shares</td>
<td>321,201</td>
<td>321,201</td>
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<tr>
<td>Outstanding – 27,952,473 Shares</td>
<td>536,640</td>
<td>536,640</td>
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<tr>
<td>Paid-in Capital</td>
<td>1,697,962</td>
<td>1,469,717</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>(133,858)</td>
<td>(36,541)</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>2,421,945</strong></td>
<td><strong>2,291,017</strong></td>
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### TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY

<table>
<thead>
<tr>
<th>Description</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>8,003,826</strong></td>
<td><strong>7,338,429</strong></td>
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*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
<table>
<thead>
<tr>
<th>OPERATING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$231,123</td>
<td>$268,564</td>
<td>$228,643</td>
</tr>
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<td>Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>273,720</td>
<td>339,817</td>
<td>321,954</td>
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<tr>
<td>Deferred Income Taxes</td>
<td>42,717</td>
<td>16,238</td>
<td>(43,997)</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>(16,309)</td>
<td>(14,472)</td>
<td>(13,841)</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>(3,073)</td>
<td>(2,311)</td>
<td>(2,556)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>(13,839)</td>
<td>(7,006)</td>
<td>(8,770)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>(54,160)</td>
<td>(39,513)</td>
<td>1,821</td>
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<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>(9,569)</td>
<td>783</td>
<td>10,126</td>
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<tr>
<td>Changes in Certain Components of Working Capital:</td>
<td></td>
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<tr>
<td>Accounts Receivable, Net</td>
<td>5,104</td>
<td>(54,730)</td>
<td>116,496</td>
</tr>
<tr>
<td>Fuel, Materials and Supplies</td>
<td>(89,058)</td>
<td>17,845</td>
<td>(21,914)</td>
</tr>
<tr>
<td>Accounts Payable</td>
<td>126,716</td>
<td>(19,536)</td>
<td>(14,114)</td>
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<tr>
<td>Customer Deposits</td>
<td>(6,280)</td>
<td>8,970</td>
<td>1,543</td>
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<tr>
<td>Accrued Taxes, Net</td>
<td>(11,210)</td>
<td>41,623</td>
<td>23,620</td>
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<tr>
<td>Other Current Assets</td>
<td>(10,730)</td>
<td>(948)</td>
<td>18,890</td>
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<tr>
<td>Other Current Liabilities</td>
<td>20,269</td>
<td>17,671</td>
<td>8,345</td>
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<tr>
<td>Net Cash Flows from Operating Activities</td>
<td>485,421</td>
<td>572,995</td>
<td>626,246</td>
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<table>
<thead>
<tr>
<th>INVESTING ACTIVITIES</th>
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<tbody>
<tr>
<td>Construction Expenditures</td>
<td>(706,315)</td>
<td>(933,162)</td>
<td>(999,603)</td>
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<tr>
<td>Acquisition of Assets</td>
<td>(2,033)</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Proceeds from Sales of Assets</td>
<td>8,293</td>
<td>9,023</td>
<td>15,443</td>
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<tr>
<td>Other</td>
<td>(1,734)</td>
<td>158</td>
<td>(1,935)</td>
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<tr>
<td>Net Cash Flows Used for Investing Activities</td>
<td>(701,789)</td>
<td>(923,981)</td>
<td>(986,095)</td>
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<table>
<thead>
<tr>
<th>FINANCING ACTIVITIES</th>
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<tr>
<td>Capital Contribution from Parent</td>
<td>-</td>
<td>-</td>
<td>70,000</td>
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<tr>
<td>Issuance of Long-term Debt – Nonaffiliated</td>
<td>491,204</td>
<td>461,912</td>
<td>408,710</td>
</tr>
<tr>
<td>Change in Short-term Debt, Net – Nonaffiliated</td>
<td>(701)</td>
<td>(502)</td>
<td>(9,163)</td>
</tr>
<tr>
<td>Change in Advances from Affiliates, Net</td>
<td>32,339</td>
<td>(79,733)</td>
<td>111,210</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Nonaffiliated</td>
<td>(305,188)</td>
<td>(17,854)</td>
<td>(12,354)</td>
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<tr>
<td>Retirement of Long-term Debt – Affiliated</td>
<td>-</td>
<td>(2)</td>
<td>(7)</td>
</tr>
<tr>
<td>Retirement of Cumulative Preferred Stock</td>
<td>-</td>
<td>(7,062)</td>
<td>(7,430)</td>
</tr>
<tr>
<td>Dividends Paid on Cumulative Preferred Stock</td>
<td>(732)</td>
<td>(732)</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>11,195</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Net Cash Flows from Financing Activities</td>
<td>222,381</td>
<td>356,027</td>
<td>360,234</td>
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<tr>
<th>SUPPLEMENTARY INFORMATION</th>
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<tbody>
<tr>
<td>Net Increase in Cash and Cash Equivalents</td>
<td>6,013</td>
<td>5,041</td>
<td>385</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
<td>6,666</td>
<td>1,625</td>
<td>1,240</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
<td>12,679</td>
<td>$12,679</td>
<td>$1,625</td>
</tr>
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</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
The notes to OPCo’s financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page H-1.

| Organization and Summary of Significant Accounting Policies | Note 1 |
| New Accounting Pronouncements and Extraordinary Item | Note 2 |
| Rate Matters | Note 4 |
| Effects of Regulation | Note 5 |
| Commitments, Guarantees and Contingencies | Note 6 |
| Benefit Plans | Note 8 |
| Business Segments | Note 10 |
| Derivatives, Hedging and Fair Value Measurements | Note 11 |
| Income Taxes | Note 12 |
| Leases | Note 13 |
| Financing Activities | Note 14 |
| Related Party Transactions | Note 15 |
| Property, Plant and Equipment | Note 16 |
| Unaudited Quarterly Financial Information | Note 17 |
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company Consolidated (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," effective January 1, 2007. As discussed in Note 8 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Ohio Power Company Consolidated (OPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. OPCo’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of OPCo’s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, OPCo’s internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of OPCo’s registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by OPCo’s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit OPCo to provide only management’s report in this annual report.
### PUBLIC SERVICE COMPANY OF OKLAHOMA

**SELECTED FINANCIAL DATA**

*(in thousands)*

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenues</td>
<td>$1,655,945 (a)</td>
<td>$1,395,550</td>
<td>$1,441,784</td>
<td>$1,304,078</td>
<td>$1,047,820</td>
</tr>
<tr>
<td>Operating Income (Loss)</td>
<td>$160,463 (a)(b)</td>
<td>$(4,835)(c)</td>
<td>$90,993</td>
<td>$118,016</td>
<td>$82,806</td>
</tr>
<tr>
<td>Net Income (Loss)</td>
<td>$78,484 (a)(b)</td>
<td>$(24,124)(c)</td>
<td>$36,860</td>
<td>$57,893</td>
<td>$37,542</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>BALANCE SHEETS DATA</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>1,192,130</td>
<td>1,182,171</td>
<td>1,187,107</td>
<td>1,175,858</td>
<td>1,117,535</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>$2,499,881</td>
<td>$2,277,010</td>
<td>$1,999,187</td>
<td>$1,819,137</td>
<td>$1,758,304</td>
</tr>
<tr>
<td>Total Assets</td>
<td>$3,100,798</td>
<td>$2,843,871 (d)</td>
<td>$2,565,579 (d)</td>
<td>$2,334,128 (d)</td>
<td>$2,062,652 (d)</td>
</tr>
<tr>
<td>Common Shareholder's Equity</td>
<td>$748,246</td>
<td>$640,898</td>
<td>$585,438</td>
<td>$548,597</td>
<td>$529,256</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>$5,262</td>
<td>$5,262</td>
<td>$5,262</td>
<td>$5,262</td>
<td>$5,262</td>
</tr>
<tr>
<td>Long-term Debt (e)</td>
<td>$884,859</td>
<td>$918,316</td>
<td>$669,998</td>
<td>$571,071</td>
<td>$546,092</td>
</tr>
<tr>
<td>Obligations Under Capital Leases (e)</td>
<td>$3,478</td>
<td>$4,028</td>
<td>$4,816</td>
<td>$2,534</td>
<td>$1,284</td>
</tr>
</tbody>
</table>

(a) Includes the net favorable effect of the recognition of off-system sales margins as ordered by the FERC in November 2008. See “Allocation of Off-system Sales Margins” section of Note 4.

(b) Includes the favorable effect of the 2008 deferral of Oklahoma ice storm expenses incurred in 2007. See “Oklahoma 2007 Ice Storms” section of Note 4.

(c) Includes expenses incurred from ice storms in January and December 2007. See “Oklahoma 2007 Ice Storms” section of Note 4.

(d) Includes reclassification of assets due to FSP FIN 39-1 adoption effective in 2008. See “FSP FIN 39-1” section of Note 2.

(e) Includes portion due within one year.
As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 527,000 retail customers in its service territory in eastern and southwestern Oklahoma. As a member of the CSW Operating Agreement with SWEPCo, PSO shares in the revenues and expenses of the members’ sales to neighboring utilities and power marketers. PSO also sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

Effective May 1, 2006, the FERC approved the removal of TCC and TNC from the CSW Operating Agreement. Under the Texas Restructuring Legislation, TCC and TNC completed the final stage of exiting the generation business and ceased serving retail load. TCC and TNC are no longer involved in the coordinated planning and operation of power supply facilities or share trading and marketing margins, as contemplated by both the CSW Operating Agreement and the SIA. Consequently, PSO’s proportionate share of trading and marketing margins increased, although the level of margins depends upon future market conditions. PSO shares these margins with its customers.

Members of the CSW Operating Agreement are compensated for energy delivered to the other member based upon the delivering member’s incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. PSO and SWEPCo share the revenues and costs of sales to neighboring utilities and power marketers made by AEPSC on their behalf based upon the relative magnitude of the energy each company provides to make such sales. PSO shares off-system sales margins, if positive on an annual basis, with its customers.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies’ and AEP West companies’ allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, 2006 net income and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on PSO’s behalf. PSO shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the AEP East companies and SWEPCo. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. PSO shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.
Effective January 1, 2007, PSO locked in margins on its ERCOT trading and marketing contracts and transferred commodity price risk to AEP Energy Partners, LP (AEPEP), a wholly-owned subsidiary of AEP. This was achieved by a combination of transferring certain existing ERCOT energy marketing contracts to AEPEP and entering into financial and physical purchase and sale agreements with AEPEP. PSO will not be a party to new contracts in ERCOT. As the contracts mature, PSO will realize the fixed margin on the portfolio of ERCOT contracts as it existed on December 31, 2006 and will not be exposed to commodity price risk and resulting income variations for these contracts.

PSO is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

**Results of Operations**

**2008 Compared to 2007**

<table>
<thead>
<tr>
<th>Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>$ (24)</td>
</tr>
<tr>
<td><strong>Changes in Gross Margin:</strong></td>
<td></td>
</tr>
<tr>
<td>Retail and Off-system Sales Margins</td>
<td>36</td>
</tr>
<tr>
<td>Transmission Revenues</td>
<td>9</td>
</tr>
<tr>
<td>Other</td>
<td>14</td>
</tr>
<tr>
<td><strong>Total Change in Gross Margin</strong></td>
<td>59</td>
</tr>
<tr>
<td><strong>Changes in Operating Expenses and Other:</strong></td>
<td></td>
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<tr>
<td>Other Operation and Maintenance</td>
<td>43</td>
</tr>
<tr>
<td>Deferral of Ice Storm Costs</td>
<td>74</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>(14)</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>2</td>
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<tr>
<td>Other Income</td>
<td>22</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>10</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(30)</td>
</tr>
<tr>
<td><strong>Total Change in Operating Expenses and Other</strong></td>
<td>107</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>(64)</td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td>$ 78</td>
</tr>
</tbody>
</table>

Net Income (Loss) increased $102 million to $78 million in 2008. The key drivers of the increase were a $107 million decrease in Operating Expenses and Other and a $59 million increase in Gross Margin, offset by a $64 million increase in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased $36 million primarily due to:
  - An $18 million increase in retail sales margins resulting from base rate increases during the year.
  - A $14 million increase due to the net favorable effect of the recognition of off-system sales margins as ordered by the FERC in November 2008. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $3 million decrease in capacity purchase power expense due to increased available owned capacity.
- Transmission Revenues increased $9 million primarily due to higher rates within SPP.
- Other revenues increased $14 million primarily due to an increase related to the recognition of the sale of SO2 allowances. See “Oklahoma 2007 Ice Storms” section of Note 4.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $43 million primarily due to:
  - An $84 million decrease due to distribution expense recorded in 2007 for ice storm costs incurred in January and December 2007. See “Oklahoma 2007 Ice Storms” section of Note 4.

  These decreases were partially offset by:
  - A $16 million increase in production operation expenses primarily due to a $10 million write-off of pre-construction costs related to the cancelled Red Rock Generating Facility. See “Red Rock Generating Facility” section of Note 4. The increase is also the result of a lawsuit settlement provision related to the Oklaunion Plant. See “Rail Transportation Litigation” section of Note 6.
  - A $12 million increase due to amortization of the deferred 2007 ice storm costs.
  - A $9 million increase in transmission operation expense primarily due to higher rates within SPP.
  - A $4 million increase in distribution maintenance expense due mainly to increased vegetation management activities and a June 2008 storm.
- Deferral of Ice Storm Costs in 2008 of $74 million results from an OCC order approving recovery of ice storm costs related to ice storms in January and December 2007. See “Oklahoma 2007 Ice Storms” section of Note 4.
- Depreciation and Amortization expenses increased $14 million primarily due to an increase related to the amortization of the Lawton Settlement regulatory assets.
- Other Income increased $22 million primarily due to interest income from the AEP East companies for the refund of off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
- Carrying Costs Income increased $10 million due to the new peaking units and deferred ice storm costs. See “Oklahoma 2007 Ice Storms” section of Note 4.
- Interest Expense increased $30 million primarily due to interest expense of $16 million to customers for off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4. The increase is also due to a $14 million increase in interest expense from long-term borrowings, partially offset by a $4 million decrease in Utility Money Pool interest.
- Income Tax Expense increased $64 million primarily due to an increase in pretax book income and state income taxes.
Net Income (Loss) decreased $61 million in 2007. The key drivers of the decrease were a $121 million increase in Operating Expenses and Other, partially offset by a $22 million increase in Gross Margin and a $38 million decrease in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased $25 million primarily due to:
  - A $19 million increase in retail sales margins mainly due to base rate adjustments during the year.
  - An $8 million increase in off-system margins retained from a net increase of $21 million from higher trading margins and decreased physical sales.
- Other revenues decreased $5 million primarily due to a $2 million decrease in rental and pole attachment income and a $1 million decrease in gains on sales of emission allowances.

Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $106 million primarily due to:
  - An $86 million increase in distribution expense resulting primarily from the ice storms in January and December 2007. See “Oklahoma 2007 Ice Storms” section of Note 4.
  - An $11 million increase in generation expenses primarily due to scheduled maintenance outages.
  - A $7 million increase in transmission expense primarily due to a $4 million increase in transmission services from other utilities and a $3 million increase in SPP charges and fees.
- Depreciation and Amortization increased $4 million primarily due to the amortization of regulatory assets related to the Lawton Settlement.
- Taxes Other Than Income Taxes increased $8 million primarily due to a sales and use tax adjustment recorded in 2006.
- Other Income increased $3 million primarily due to higher carrying charges on recovery of regulatory assets related to the Lawton Settlement.
- Interest Expense increased $6 million primarily due to increased borrowings in support of capital spending.
- Income Tax Expense decreased $38 million primarily due to a decrease in pretax book income and the recording of state income tax adjustments.
Financial Condition

Credit Ratings

Current ratings for PSO are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Moody’s</th>
<th>S&amp;P</th>
<th>Fitch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Senior Unsecured Debt</td>
<td>Baa1</td>
<td>BBB</td>
<td>BBB+</td>
</tr>
</tbody>
</table>

S&P and Fitch currently have PSO on stable outlook. In February 2009, Moody’s affirmed its stable rating outlook for PSO. If PSO receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Liquidity

In 2008, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting PSO’s access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on PSO since it relies on continuing access to capital to fund operations and capital expenditures.

PSO participates in the Utility Money Pool, which provides access to AEP’s liquidity. PSO has $50 million of Senior Unsecured Notes that will mature in June 2009. To the extent refinancing is unavailable due to the challenging credit markets in 2009, PSO will rely upon cash flows from operations and access to the Utility Money Pool to fund its maturity, current operations and capital expenditures.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of liquidity.

Cash Flow

Cash flows for 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
</tr>
<tr>
<td>Cash Flows from (Used for):</td>
</tr>
<tr>
<td>Operating Activities</td>
</tr>
<tr>
<td>Investing Activities</td>
</tr>
<tr>
<td>Financing Activities</td>
</tr>
<tr>
<td>Net Increase (Decrease) in Cash and Cash Equivalents</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
</tr>
</tbody>
</table>

Operating Activities

Net Cash Flows from Operating Activities were $168 million in 2008. PSO produced Net Income of $78 million during the period and had noncash expense items of $105 million for Depreciation and Amortization and $68 million for Deferred Income Taxes. PSO established a $74 million regulatory asset for an OCC order approving recovery of ice storm costs related to storms in January and December 2007. PSO recorded a Provision for Revenue Refund of $52 million to its customers for off-system sales margins to be received from the AEP East companies as ordered by the FERC related to the SIA. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $89 million outflow from Accounts Payable was primarily due to a decrease in accounts payable accruals and purchased power payable. The $47 million inflow from Fuel Over/Under-Recovery, Net resulted from revenues exceeding recoverable fuel costs. The balance will be refunded in future periods. The
A $41 million change in Accounts Receivable, Net was primarily the result of the refund to be received from the AEP East companies related to the SIA. The $29 million inflow from Accrued Taxes, Net was the result of a refund for the 2007 overpayment of federal income taxes and increased accruals related to property and income taxes.

Net Cash Flows from Operating Activities were $113 million in 2007. PSO incurred a Net Loss of $24 million during the period and had a noncash expense item of $92 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $28 million outflow from Accrued Taxes, Net was primarily due to an increase in federal tax accrual net of the fourth quarter payment. The $25 million inflow from Accounts Payable was primarily related to December 2007 ice storm expenses. The $20 million inflow from Margin Deposits was primarily due to gas trading activities. The $19 million inflow from Fuel Over/Under Recovery, Net was primarily due to lower fuel cost.

Net Cash Flows from Operating Activities were $142 million in 2006. PSO produced Net Income of $37 million during the period and had a noncash expense item of $88 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $101 million inflow from Fuel Over/Under-Recovery, Net resulted from increased fuel recovery. The $33 million outflow from Accounts Receivable, Net was primarily due to an increase in PSO’s proportionate share of trading and marketing as a result of the changes in the CSW Operating Agreement and the SIA. The $22 million outflow from Margin Deposits was primarily due to the increased trading related deposits resulting from the amended SIA.

**Investing Activities**

Net Cash Flows Used for Investing Activities during 2008, 2007 and 2006 were $233 million, $361 million and $240 million, respectively. Construction Expenditures of $286 million, $315 million and $240 million in 2008, 2007 and 2006, respectively, were primarily related to projects for improved generation, transmission and distribution service reliability. In addition, during 2008, PSO had a net decrease of $51 million in investments in the Utility Money Pool, and during 2007, PSO had a net increase of $51 million in investments in the Utility Money Pool.

**Financing Activities**

Net Cash Flows from Financing Activities were $65 million during 2008. PSO had a net increase of $70 million in borrowings from the Utility Money Pool. PSO repurchased $34 million in Pollution Control Bonds in May 2008. PSO received capital contributions from the Parent of $30 million.

Net Cash Flows from Financing Activities were $248 million during 2007. PSO issued $250 million of Senior Unsecured Notes. PSO received capital contributions from the Parent of $80 million. PSO had a net decrease in borrowings by $76 million from the Utility Money Pool.

Net Cash Flows from Financing Activities were $98 million during 2006. PSO issued $150 million of Senior Unsecured Notes and retired $50 million of Notes Payable – Affiliated.
Summary Obligation Information

PSO’s contractual cash obligations include amounts reported on PSO’s Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes PSO’s contractual cash obligations at December 31, 2008:

### Payments Due by Period
(in millions)

<table>
<thead>
<tr>
<th>Contractual Cash Obligations</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates (a)</td>
<td>$ 70.3</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$ 70.3</td>
</tr>
<tr>
<td>Interest on Fixed Rate Portion of Long-term Debt (b)</td>
<td>50.3</td>
<td>89.3</td>
<td>76.7</td>
<td>656.8</td>
<td>873.1</td>
</tr>
<tr>
<td>Fixed Rate Portion of Long-term Debt (c)</td>
<td>50.0</td>
<td>225.0</td>
<td>-</td>
<td>612.7</td>
<td>887.7</td>
</tr>
<tr>
<td>Capital Lease Obligations (d)</td>
<td>1.4</td>
<td>1.8</td>
<td>0.1</td>
<td>0.3</td>
<td>3.6</td>
</tr>
<tr>
<td>Noncancelable Operating Leases (d)</td>
<td>5.6</td>
<td>22.6</td>
<td>0.6</td>
<td>0.6</td>
<td>29.4</td>
</tr>
<tr>
<td>Fuel Purchase Contracts (e)</td>
<td>244.7</td>
<td>120.4</td>
<td>42.6</td>
<td>-</td>
<td>407.7</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (f)</td>
<td>13.1</td>
<td>14.5</td>
<td>-</td>
<td>-</td>
<td>27.6</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (g)</td>
<td>10.6</td>
<td>51.4</td>
<td>73.3</td>
<td>-</td>
<td>135.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 446.0</td>
<td>$ 525.0</td>
<td>$ 193.3</td>
<td>$ 1,270.4</td>
<td>$ 2,434.7</td>
</tr>
</tbody>
</table>

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 14. Represents principal only excluding interest.
(d) See Note 13.
(e) Represents contractual obligations to purchase coal, natural gas and other consumable as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual obligations for energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

PSO’s FIN 48 liabilities of $13 million are not included above because PSO cannot reasonably estimate the cash flows by period.

AEP’s minimum pension funding requirements are not included in the above table. As of December 31, 2008, the decline in pension asset values will not require AEP to make a contribution in 2009. AEP will need to make minimum contributions to the pension plan of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

As of December 31, 2008, PSO had no outstanding standby letters of credit or guarantees of performance.

### Significant Factors

#### New Generation

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of relevant factors.

#### Litigation and Regulatory Activity

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect PSO’s net income, financial condition and cash flows.
Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.
Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section. The following tables provide information about AEP’s risk management activities’ effect on PSO.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in PSO’s Balance Sheet as of December 31, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

<table>
<thead>
<tr>
<th>Reconciliation of MTM Risk Management Contracts to Balance Sheet</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 31, 2008</td>
</tr>
<tr>
<td>(in thousands)</td>
</tr>
<tr>
<td>MTM Risk Management Contracts</td>
</tr>
<tr>
<td>Current Assets         $ 5,830</td>
</tr>
<tr>
<td>Noncurrent Assets      917</td>
</tr>
<tr>
<td>Total MTM Derivative Contract Assets</td>
</tr>
<tr>
<td>Current Liabilities    (4,780)</td>
</tr>
<tr>
<td>Noncurrent Liabilities (307)</td>
</tr>
<tr>
<td>Total MTM Derivative Contract Liabilities</td>
</tr>
<tr>
<td>Total MTM Derivative Contract Net Assets (Liabilities)</td>
</tr>
</tbody>
</table>

(a) See “Natural Gas Contracts with DETM” section of Note 15.
<table>
<thead>
<tr>
<th>Description</th>
<th>Amount (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total MTM Risk Management Contract Net Assets at December 31, 2007</strong></td>
<td>$ 6,981</td>
</tr>
<tr>
<td>(Gain) Loss from Contracts Realized/Settled During the Period and Entered</td>
<td>(6,336)</td>
</tr>
<tr>
<td>in a Prior Period</td>
<td></td>
</tr>
<tr>
<td>Fair Value of New Contracts at Inception When Entered During the Period (a)</td>
<td>-</td>
</tr>
<tr>
<td>Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option</td>
<td>-</td>
</tr>
<tr>
<td>Contracts Entered During the Period</td>
<td>-</td>
</tr>
<tr>
<td>Change in Fair Value Due to Valuation Methodology Changes on Forward</td>
<td>18</td>
</tr>
<tr>
<td>Contracts (b)</td>
<td></td>
</tr>
<tr>
<td>Changes in Fair Value Due to Market Fluctuations During the Period (c)</td>
<td>(120)</td>
</tr>
<tr>
<td>Changes in Fair Value Allocated to Regulated Jurisdictions (d)</td>
<td>1,117</td>
</tr>
<tr>
<td><strong>Total MTM Risk Management Contract Net Assets</strong></td>
<td>1,660</td>
</tr>
<tr>
<td>DETM Assignment (e)</td>
<td>(149)</td>
</tr>
<tr>
<td>Collateral Deposits</td>
<td>105</td>
</tr>
<tr>
<td><strong>Ending Net Risk Management Assets (Liabilities) at December 31, 2008</strong></td>
<td>$ 1,616</td>
</tr>
</tbody>
</table>

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Represents the impact of applying AEP’s credit risk when measuring the fair value of derivative liabilities according to SFAS 157.

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

(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities.

(e) See “Natural Gas Contracts with DETM” section of Note 15.
Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

<table>
<thead>
<tr>
<th>Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets</th>
<th>Fair Value of Contracts as of December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>$ (369)</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>1,422</td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td>(3)</td>
</tr>
<tr>
<td>Total</td>
<td>$ 1,050</td>
</tr>
</tbody>
</table>

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

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

Management uses interest rate derivative transactions to manage interest rate exposure on anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on PSO’s Balance Sheets and the reasons for the changes from December 31, 2007 to December 31, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

<table>
<thead>
<tr>
<th>Total Accumulated Other Comprehensive Income (Loss) Activity</th>
<th>Year Ended December 31, 2008 (in thousands)</th>
<th>Interest Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beginning Balance in AOCI December 31, 2007</td>
<td>$ (887)</td>
<td></td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Reclassifications from AOCI for Cash Flow Hedges Settled</td>
<td>183</td>
<td></td>
</tr>
<tr>
<td>Ending Balance in AOCI December 31, 2008</td>
<td>$ (704)</td>
<td></td>
</tr>
</tbody>
</table>

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $183 thousand loss.
Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2008, a near term typical change in commodity prices is not expected to have a material effect on PSO’s net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the periods indicated:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008 (in thousands)</th>
<th>December 31, 2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>End</td>
<td>High</td>
<td>Average</td>
</tr>
<tr>
<td>$4</td>
<td>$164</td>
<td>$44</td>
</tr>
<tr>
<td>End</td>
<td>High</td>
<td>Average</td>
</tr>
<tr>
<td>$13</td>
<td>$189</td>
<td>$53</td>
</tr>
</tbody>
</table>

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management’s backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes PSO’s VaR calculation is conservative.

As PSO’s VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand PSO’s exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translated into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which PSO’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on PSO’s debt portfolio is $1.7 million.
# PUBLIC SERVICE COMPANY OF OKLAHOMA
## STATEMENTS OF OPERATIONS
### For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REVENUES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Generation, Transmission and Distribution</td>
<td>$1,549,490</td>
<td>$1,321,919</td>
<td>$1,384,549</td>
</tr>
<tr>
<td>Sales to AEP Affiliates</td>
<td>101,602</td>
<td>69,106</td>
<td>51,993</td>
</tr>
<tr>
<td>Other</td>
<td>4,853</td>
<td>4,525</td>
<td>5,242</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,655,945</td>
<td>1,395,550</td>
<td>1,441,784</td>
</tr>
</tbody>
</table>

| **EXPENSES**            |        |        |        |
| Fuel and Other Consumables Used for Electric Generation | 774,089 | 590,053 | 703,252 |
| Purchased Electricity for Resale | 270,536 | 246,928 | 199,094 |
| Purchased Electricity from AEP Affiliates | 59,344 | 66,324 | 69,406 |
| Other Operation         | 208,930 | 179,700 | 170,201 |
| Maintenance             | 113,305 | 185,554 | 88,676 |
| Deferral of Ice Storm Costs | (74,217) | - | - |
| Depreciation and Amortization | 105,249 | 91,611 | 87,543 |
| Taxes Other Than Income Taxes | 38,246 | 40,215 | 32,619 |
| **TOTAL**               | 1,495,482 | 1,400,385 | 1,350,791 |

**OPERATING INCOME (LOSS)**

160,463 (4,835) 90,993

**Other Income (Expense):**

- Interest Income: 25,248 3,564 1,917
- Carrying Costs Income: 10,138 325 -
- Allowance for Equity Funds Used During Construction: 1,822 1,367 715
- Interest Expense: (76,910) (46,560) (40,778)

**INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)**

120,761 (46,139) 52,847

**Income Tax Expense (Credit)**

42,277 (22,015) 15,987

**NET INCOME (LOSS)**

78,484 (24,124) 36,860

**Preferred Stock Dividend Requirements**

212 213 213

**EARNINGS (LOSS) APPLICABLE TO COMMON STOCK**

$78,272 $(24,337) $36,647

*The common stock of PSO is wholly-owned by AEP.*

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
### Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss)

For the Years Ended December 31, 2008, 2007 and 2006

(in thousands)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Stock</td>
<td>$157,230</td>
<td>$157,230</td>
<td>$157,230</td>
<td>$157,230</td>
</tr>
<tr>
<td>Paid-in Capital</td>
<td>$230,016</td>
<td>$230,016</td>
<td>$310,016</td>
<td>$340,016</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>$162,615</td>
<td>$199,262</td>
<td>$174,539</td>
<td>$251,704</td>
</tr>
<tr>
<td>Accumulated Other</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Comprehensive Income</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Loss</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### COMPREHENSIVE INCOME

**Other Comprehensive Income, Net of Taxes:**
- Cash Flow Hedges, Net of Tax of $22
- Minimum Pension Liability, Net of Tax of $14

**NET INCOME**

**Total Comprehensive Income**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Preferred Stock Dividends</td>
<td>(213)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>548,597</td>
<td>548,384</td>
<td>585,438</td>
<td>640,898</td>
</tr>
</tbody>
</table>

#### COMPREHENSIVE LOSS

**Other Comprehensive Income, Net of Taxes:**
- Cash Flow Hedges, Net of Tax of $99

**NET LOSS**

**Total Comprehensive Loss**

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2005</th>
<th>December 31, 2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>FIN 48 Adoption, Net of Tax</td>
<td>(386)</td>
<td>(386)</td>
</tr>
<tr>
<td>Capital Contribution from Parent</td>
<td>80,000</td>
<td>80,000</td>
</tr>
<tr>
<td>Preferred Stock Dividends</td>
<td>(213)</td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>664,839</td>
<td></td>
</tr>
</tbody>
</table>

#### COMPREHENSIVE INCOME

**Other Comprehensive Income, Net of Taxes:**
- Cash Flow Hedges, Net of Tax of $99

**NET INCOME**

**Total Comprehensive Income**

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2005</th>
<th>December 31, 2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preferred Stock Dividends</td>
<td>(213)</td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>748,246</td>
<td></td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
## PUBLIC SERVICE COMPANY OF OKLAHOMA
### BALANCE SHEETS
#### ASSETS
December 31, 2008 and 2007
(in thousands)

<table>
<thead>
<tr>
<th>CURRENT ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$1,345</td>
<td>$1,370</td>
</tr>
<tr>
<td>Advances to Affiliates</td>
<td>-</td>
<td>51,202</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customers</td>
<td>39,823</td>
<td>74,330</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>138,665</td>
<td>59,835</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>8,441</td>
<td>10,315</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts</td>
<td>(20)</td>
<td>-</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>186,909</td>
<td>144,480</td>
</tr>
<tr>
<td>Fuel</td>
<td>27,060</td>
<td>19,394</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>44,047</td>
<td>47,691</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>5,830</td>
<td>33,308</td>
</tr>
<tr>
<td>Accrued Tax Benefits</td>
<td>3,876</td>
<td>31,756</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>12,494</td>
<td>27,117</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>281,561</td>
<td>356,318</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PROPERTY, PLANT AND EQUIPMENT</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>1,266,716</td>
<td>1,110,657</td>
</tr>
<tr>
<td>Transmission</td>
<td>622,665</td>
<td>569,746</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,468,481</td>
<td>1,337,038</td>
</tr>
<tr>
<td>Other</td>
<td>248,897</td>
<td>241,722</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>85,252</td>
<td>200,018</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>3,692,011</td>
<td>3,459,181</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>1,192,130</td>
<td>1,182,171</td>
</tr>
<tr>
<td><strong>TOTAL - NET</strong></td>
<td>2,499,881</td>
<td>2,277,010</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OTHER NONCURRENT ASSETS</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Assets</td>
<td>304,737</td>
<td>158,731</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>917</td>
<td>3,358</td>
</tr>
<tr>
<td>Deferred Charges and Other</td>
<td>13,702</td>
<td>48,454</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>319,356</td>
<td>210,543</td>
</tr>
</tbody>
</table>

| TOTAL ASSETS                       | $3,100,798| $2,843,871|

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
## PUBLIC SERVICE COMPANY OF OKLAHOMA
### BALANCE SHEETS
#### LIABILITIES AND SHAREHOLDERS’ EQUITY
December 31, 2008 and 2007

<table>
<thead>
<tr>
<th>LIABILITIES AND SHAREHOLDERS’ EQUITY</th>
<th>2008 (in thousands)</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CURRENT LIABILITIES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advances from Affiliates</td>
<td>$ 70,308</td>
<td>$ -</td>
</tr>
<tr>
<td>Accounts Payable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>84,121</td>
<td>189,032</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>86,407</td>
<td>80,316</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year – Nonaffiliated</td>
<td>50,000</td>
<td>$ -</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>4,753</td>
<td>27,118</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>40,528</td>
<td>41,477</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>19,000</td>
<td>18,374</td>
</tr>
<tr>
<td>Regulatory Liability for Over-Recovered Fuel Costs</td>
<td>58,395</td>
<td>11,697</td>
</tr>
<tr>
<td>Provision for Revenue Refund</td>
<td>52,100</td>
<td>$ -</td>
</tr>
<tr>
<td>Other</td>
<td>61,194</td>
<td>57,708</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>526,806</td>
<td>425,722</td>
</tr>
<tr>
<td><strong>NONCURRENT LIABILITIES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long-term Debt – Nonaffiliated</td>
<td>834,859</td>
<td>918,316</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>378</td>
<td>2,808</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>514,720</td>
<td>456,497</td>
</tr>
<tr>
<td>Regulatory Liabilities and Deferred Investment Tax Credits</td>
<td>323,750</td>
<td>338,788</td>
</tr>
<tr>
<td>Deferred Credits and Other</td>
<td>146,777</td>
<td>55,580</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,820,484</td>
<td>1,771,989</td>
</tr>
<tr>
<td><strong>TOTAL LIABILITIES</strong></td>
<td>2,347,290</td>
<td>2,197,711</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>5,262</td>
<td>5,262</td>
</tr>
<tr>
<td>Commitments and Contingencies (Note 6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>COMMON SHAREHOLDER’S EQUITY</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Common Stock – Par Value – $15 Per Share:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Authorized – 11,000,000 Shares</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Issued – 10,482,000 Shares</td>
<td>157,230</td>
<td>157,230</td>
</tr>
<tr>
<td>Outstanding – 9,013,000 Shares</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Paid-in Capital</td>
<td>340,016</td>
<td>310,016</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>251,704</td>
<td>174,539</td>
</tr>
<tr>
<td>Accumulated Other Comprehensive Income (Loss)</td>
<td>(704)</td>
<td>(887)</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>748,246</td>
<td>640,898</td>
</tr>
<tr>
<td><strong>TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY</strong></td>
<td>$ 3,100,798</td>
<td>$ 2,843,871</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
## OPERATING ACTIVITIES

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td>$ 78,484</td>
<td>$(24,124)</td>
<td>$ 36,860</td>
</tr>
<tr>
<td><strong>Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>105,249</td>
<td>91,611</td>
<td>87,543</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>67,874</td>
<td>31,362</td>
<td>(23,672)</td>
</tr>
<tr>
<td>Provision for Revenue Refund</td>
<td>52,100</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Carrying Costs Income</td>
<td>(10,138)</td>
<td>(325)</td>
<td>-</td>
</tr>
<tr>
<td>Deferral of Ice Storm Costs</td>
<td>(74,217)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>(1,822)</td>
<td>(1,367)</td>
<td>(715)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>5,151</td>
<td>11,285</td>
<td>(15,516)</td>
</tr>
<tr>
<td>Unrealized Forward Commitments, Net</td>
<td>(5,263)</td>
<td>(11,919)</td>
<td>4,099</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>6,117</td>
<td>(38,902)</td>
<td>(5,928)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>(6,774)</td>
<td>8,114</td>
<td>7,741</td>
</tr>
<tr>
<td><strong>Total Adjustments</strong></td>
<td>167,956</td>
<td>112,938</td>
<td>142,367</td>
</tr>
</tbody>
</table>

## INVESTING ACTIVITIES

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Expenditures</td>
<td>(285,826)</td>
<td>(314,568)</td>
<td>(240,238)</td>
</tr>
<tr>
<td>Change in Advances to Affiliates, Net</td>
<td>51,202</td>
<td>51,202</td>
<td>-</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(1,409)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>2,564</td>
<td>1,395</td>
<td>(13,481)</td>
</tr>
<tr>
<td>Other</td>
<td>5</td>
<td>3,044</td>
<td>6</td>
</tr>
<tr>
<td><strong>Net Cash Flows Used for Investing Activities</strong></td>
<td>(233,464)</td>
<td>(360,854)</td>
<td>(240,006)</td>
</tr>
</tbody>
</table>

## FINANCING ACTIVITIES

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Contribution from Parent</td>
<td>30,000</td>
<td>80,000</td>
<td>-</td>
</tr>
<tr>
<td>Issuance of Long-term Debt – Nonaffiliated</td>
<td>-</td>
<td>258,339</td>
<td>148,695</td>
</tr>
<tr>
<td>Change in Advances from Affiliates, Net</td>
<td>70,308</td>
<td>(76,323)</td>
<td>440</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Nonaffiliated</td>
<td>(33,700)</td>
<td>(12,660)</td>
<td>-</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Affiliated</td>
<td>-</td>
<td>-</td>
<td>(50,000)</td>
</tr>
<tr>
<td>Principal Payments for Capital Lease Obligations</td>
<td>(1,551)</td>
<td>(1,508)</td>
<td>(1,152)</td>
</tr>
<tr>
<td>Dividends Paid on Cumulative Preferred Stock</td>
<td>(212)</td>
<td>(213)</td>
<td>(213)</td>
</tr>
<tr>
<td>Other</td>
<td>638</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Net Cash Flows from Financing Activities</strong></td>
<td>65,483</td>
<td>247,635</td>
<td>97,770</td>
</tr>
</tbody>
</table>

## NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Increase (Decrease) in Cash and Cash Equivalents</strong></td>
<td>(25)</td>
<td>(281)</td>
<td>131</td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at Beginning of Period</strong></td>
<td>1,370</td>
<td>1,651</td>
<td>1,520</td>
</tr>
<tr>
<td><strong>Cash and Cash Equivalents at End of Period</strong></td>
<td>$ 1,345</td>
<td>$ 1,370</td>
<td>$ 1,651</td>
</tr>
</tbody>
</table>

## SUPPLEMENTARY INFORMATION

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash Paid for Interest, Net of Capitalized Amounts</td>
<td>$ 53,132</td>
<td>$ 40,692</td>
<td>$ 32,652</td>
</tr>
<tr>
<td>Net Cash Paid (Received) for Income Taxes</td>
<td>(50,022)</td>
<td>(23,559)</td>
<td>29,879</td>
</tr>
<tr>
<td>Noncash Acquisitions Under Capital Leases</td>
<td>1,008</td>
<td>826</td>
<td>3,435</td>
</tr>
<tr>
<td>Construction Expenditures Included in Accounts Payable at December 31,</td>
<td>18,004</td>
<td>26,931</td>
<td>14,928</td>
</tr>
<tr>
<td>Revenue Refund Included in Accounts Receivable at December 31,</td>
<td>72,311</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
## PUBLIC SERVICE COMPANY OF OKLAHOMA
### INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO’s financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page H-1.

<table>
<thead>
<tr>
<th>Footnote Reference</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Note 1</td>
<td>Organization and Summary of Significant Accounting Policies</td>
</tr>
<tr>
<td>Note 2</td>
<td>New Accounting Pronouncements and Extraordinary Item</td>
</tr>
<tr>
<td>Note 4</td>
<td>Rate Matters</td>
</tr>
<tr>
<td>Note 5</td>
<td>Effects of Regulation</td>
</tr>
<tr>
<td>Note 6</td>
<td>Commitments, Guarantees and Contingencies</td>
</tr>
<tr>
<td>Note 8</td>
<td>Benefit Plans</td>
</tr>
<tr>
<td>Note 10</td>
<td>Business Segments</td>
</tr>
<tr>
<td>Note 11</td>
<td>Derivatives, Hedging and Fair Value Measurements</td>
</tr>
<tr>
<td>Note 12</td>
<td>Income Taxes</td>
</tr>
<tr>
<td>Note 13</td>
<td>Leases</td>
</tr>
<tr>
<td>Note 14</td>
<td>Financing Activities</td>
</tr>
<tr>
<td>Note 15</td>
<td>Related Party Transactions</td>
</tr>
<tr>
<td>Note 16</td>
<td>Property, Plant and Equipment</td>
</tr>
<tr>
<td>Note 17</td>
<td>Unaudited Quarterly Financial Information</td>
</tr>
</tbody>
</table>
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Public Service Company of Oklahoma:

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2008 and 2007, and the related statements of operations, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 8 to the financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
The management of Public Service Company of Oklahoma (PSO) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. PSO’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of PSO’s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, PSO’s internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of PSO’s registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by PSO’s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit PSO to provide only management’s report in this annual report.
**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED**
**SELECTED CONSOLIDATED FINANCIAL DATA**
(in thousands)

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>STATEMENTS OF INCOME DATA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Revenues</td>
<td>$ 1,554,762</td>
<td>$ 1,483,462</td>
<td>$ 1,431,839</td>
<td>$ 1,405,379</td>
<td>$ 1,091,072</td>
</tr>
<tr>
<td>Operating Income</td>
<td>$ 172,645</td>
<td>$ 134,702</td>
<td>$ 189,618</td>
<td>$ 160,537</td>
<td>$ 179,239</td>
</tr>
<tr>
<td>Income Before Cumulative Effect of Accounting Changes</td>
<td>$ 92,754</td>
<td>$ 66,264</td>
<td>$ 91,723</td>
<td>$ 75,190</td>
<td>$ 89,457</td>
</tr>
<tr>
<td>Cumulative Effect of Accounting Changes, Net of Tax</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(1,252)</td>
<td>-</td>
</tr>
<tr>
<td>Net Income</td>
<td>$ 92,754</td>
<td>$ 66,264</td>
<td>$ 91,723</td>
<td>$ 73,938</td>
<td>$ 89,457</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
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<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>BALANCE SHEETS DATA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property, Plant and Equipment</td>
<td>$ 5,576,528</td>
<td>$ 4,876,912</td>
<td>$ 4,328,247</td>
<td>$ 4,006,639</td>
<td>$ 3,892,508</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>2,014,154</td>
<td>1,939,044</td>
<td>1,834,145</td>
<td>1,776,216</td>
<td>1,710,850</td>
</tr>
<tr>
<td>Total Assets</td>
<td>$ 4,253,085</td>
<td>$ 3,488,386 (a)</td>
<td>$ 3,175,071 (a)</td>
<td>$ 2,772,411 (a)</td>
<td>$ 2,641,897 (a)</td>
</tr>
<tr>
<td>Common Shareholder's Equity</td>
<td>$ 1,248,653</td>
<td>$ 972,955</td>
<td>$ 821,202</td>
<td>$ 782,378</td>
<td>$ 768,618</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>$ 4,697</td>
<td>$ 4,697</td>
<td>$ 4,697</td>
<td>$ 4,700</td>
<td>$ 4,700</td>
</tr>
<tr>
<td>Long-term Debt (b)</td>
<td>$ 1,478,149 (c)</td>
<td>$ 1,197,217 (c)</td>
<td>$ 729,006</td>
<td>$ 744,641</td>
<td>$ 805,369</td>
</tr>
<tr>
<td>Obligations Under Capital Leases (b)</td>
<td>$ 112,725 (d)</td>
<td>$ 100,320 (d)</td>
<td>$ 84,715 (d)</td>
<td>$ 42,545</td>
<td>$ 34,546</td>
</tr>
</tbody>
</table>

(a) Includes reclassification of assets due to FSP FIN 39-1 adoption effective in 2008. See “FSP FIN 39-1” section of Note 2.
(b) Includes portion due within one year.
(c) Increased primarily due to the construction of new generation.
(d) Increased primarily due to new leases for coal handling equipment.
As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 471,000 retail customers in its service territory in northeastern Texas, northwestern Louisiana and western Arkansas. SWEPCo consolidates its wholly-owned subsidiaries Southwest Arkansas Utilities Corporation and Dolet Hills Lignite Company, LLC, a variable interest entity. SWEPCo also consolidates Sabine Mining Company, a variable interest entity. As a member of the CSW Operating Agreement with PSO, SWEPCo shares in the revenues and expenses of the members’ sales to neighboring utilities and power marketers. SWEPCo also sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

Effective May 1, 2006, the FERC approved the removal of TCC and TNC from the CSW Operating Agreement. Under the Texas Restructuring Legislation, TCC and TNC completed the final stage of exiting the generation business and ceased serving retail load. TCC and TNC are no longer involved in the coordinated planning and operation of power supply facilities or share trading and marketing margins, as contemplated by both the CSW Operating Agreement and the SIA. Consequently, SWEPCo’s proportionate share of trading and marketing margins increased, although the level of margins depends upon future market conditions. SWEPCo shares these margins with its customers.

Members of the CSW Operating Agreement are compensated for energy delivered to the other member based upon the delivering member’s incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. PSO and SWEPCo share the revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on their behalf based upon the relative magnitude of the energy each company provides to make such sales. SWEPCo shares these margins with its customers.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies’ and AEP West companies’ allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, 2006 net income and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on SWEPCo’s behalf. SWEPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the AEP East companies and PSO. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. SWEPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Effective January 1, 2007, SWEPCo locked in margins on its ERCOT trading and marketing contracts and transferred commodity price risk to AEPEP, a wholly-owned subsidiary of AEP. This was achieved by a combination of transferring certain existing ERCOT energy marketing contracts to AEPEP and entering into financial and physical purchase and sale agreements with AEPEP. SWEPCo will not be a party to new contracts in
ERCOT. As the contracts mature, SWEPCo will realize the fixed margin on the portfolio of ERCOT contracts as it existed on December 31, 2006 and will not be exposed to commodity price risk and resulting income variations for these contracts.

SWEPCo is jointly and severally liable for activity conducted by AEPSC on the behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Results of Operations

2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008

<table>
<thead>
<tr>
<th>Net Income (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year Ended December 31, 2007</td>
</tr>
<tr>
<td>Changes in Gross Margin:</td>
</tr>
<tr>
<td>Retail and Off-system Sales Margins (a)</td>
</tr>
<tr>
<td>Transmission Revenues</td>
</tr>
<tr>
<td>Other</td>
</tr>
<tr>
<td>Total Change in Gross Margin</td>
</tr>
<tr>
<td>Changes in Operating Expenses and Other:</td>
</tr>
<tr>
<td>Other Operation and Maintenance</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
</tr>
<tr>
<td>Other Income</td>
</tr>
<tr>
<td>Interest Expense</td>
</tr>
<tr>
<td>Total Change in Operating Expenses and Other</td>
</tr>
<tr>
<td>Income Tax Expense</td>
</tr>
<tr>
<td>Year Ended December 31, 2008</td>
</tr>
</tbody>
</table>

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

Net Income increased $27 million in 2008. The key drivers of the increase were a $63 million increase in Gross Margin, partially offset by a $21 million increase in Operating Expenses and Other and a $15 million increase in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased $56 million primarily due to:
  - A $22 million net favorable effect of the recognition of off-system sales margins as ordered by the FERC in November 2008. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $31 million increase in fuel recovery resulting from a $17 million refund provision booked in 2007 pursuant to an unfavorable ALJ ruling in the Texas Fuel Reconciliation proceeding, lower fuel expense of $5 million, lower purchased power capacity expense of $5 million and increased wholesale revenue of $2 million.
- Transmission Revenues increased $9 million primarily due to higher rates in the SPP region.
- Other revenues decreased $2 million primarily due to a $12 million decrease in gains on sales of emission allowances partially offset by a $9 million revenue increase in coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC, to Cleco Corporation, a nonaffiliated entity. The increase in coal deliveries was the result of planned and forced outages during 2007 at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation. The increased revenue from coal deliveries was offset by a corresponding increase in Other Operation and Maintenance expenses from mining operations as discussed below.
Operating Expenses and Other and Income Tax Expense changed between years as indicated:

- Other Operation and Maintenance expenses increased $26 million primarily due to:
  - A $12 million increase in expenses for coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC. The increased expenses for coal deliveries were partially offset by a corresponding increase in revenues from mining operations as discussed above.
  - A $10 million increase in distribution expenses associated with storm restoration expenses from Hurricanes Ike and Gustav.
- Depreciation and Amortization increased $6 million primarily due to higher depreciable asset balances.
- Taxes Other Than Income Taxes decreased $7 million primarily due to a decrease in state and local franchise tax from refunds related to prior years.
- Other Income increased $37 million primarily due to:
  - $26 million of interest income from the AEP East companies for the refund of off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $6 million increase in interest income resulting from fuel under-recovery, a Texas franchise tax refund and Utility Money Pool.
  - A $5 million increase in the equity component of AFUDC as a result of construction at the Turk Plant and Stall Unit. See Note 4.
- Interest Expense increased $33 million primarily due to:
  - Interest expense of $17 million to customers for off-system sales margins in accordance with the FERC’s order related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $27 million increase from higher long-term debt outstanding, partially offset by a $10 million increase in the debt component of AFUDC due to new generation projects and a $3 million decrease in Utility Money Pool interest expense.
- Income Tax Expense increased $15 million primarily due to an increase in pretax book income and state income taxes, partially offset by the recording of federal income tax adjustments.
Net Income decreased $26 million in 2007. The key drivers of the decrease were a $26 million decrease in Gross Margin and a $25 million increase in Operating Expenses and Other, partially offset by a $26 million decrease in Income Tax Expense.

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

- Retail and Off-system Sales Margins decreased $13 million primarily due to:
  - A $17 million provision related to a SWEPCo Texas fuel reconciliation proceeding.
  - An $8 million decrease from higher sharing of net realized off-system sales margins.
  These decreases were partially offset by:
  - A $16 million increase in retail sales margins related to a combination of higher average usage and increased retail customers.
- Other revenues decreased $13 million primarily due to an $8 million decrease in gains on sales of emission allowances and a $3 million decrease in revenue from coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC, to outside parties. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.
Operating Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $19 million primarily due to the following:
  - A $14 million increase in maintenance expenses from planned and forced outages at the Welsh, Dolet Hills, Flint Creek, Knox Lee and Pirkey Plants.
  - A $9 million increase in transmission expenses primarily related to higher SPP administration fees and transmission services from other utilities.

These increases were partially offset by:

- A $4 million decrease in expenses primarily resulting from decreased coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC, due to planned and forced outages at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation, a nonaffiliated entity.

- Depreciation and Amortization expense increased $7 million primarily due to higher depreciable asset balances.
- Taxes Other Than Income Taxes increased $3 million primarily due to a sales and use tax adjustment recorded in 2006.
- Other Income increased $9 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects at the Turk Plant, Mattison Plant and Stall Unit. See Note 4.
- Interest Expense increased $5 million primarily due to higher interest of $12 million related to higher long-term debt, partially offset by an $8 million increase in the debt component of AFUDC due to new generation projects at the Turk Plant, Mattison Plant and Stall Unit. See Note 4.
- Income Tax Expense decreased $26 million primarily due to a decrease in pretax book income and the recording of state income tax adjustments.

Financial Condition

Credit Ratings

Current ratings for SWEPCo are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Moody’s</th>
<th>S&amp;P</th>
<th>Fitch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Senior Unsecured Debt</td>
<td>Baa1</td>
<td>BBB</td>
<td>BBB+</td>
</tr>
</tbody>
</table>

S&P and Fitch currently have SWEPCo on stable outlook. In February 2009, Moody’s placed SWEPCo on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries. If SWEPCo receives a downgrade from any of the rating agencies listed above, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Liquidity

In 2008, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting SWEPCo’s access to capital, liquidity and cost of capital. The uncertainties in the credit markets could have significant implications on SWEPCo since it relies on continuing access to capital to fund operations and capital expenditures.

SWEPCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. SWEPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund its current operations and capital expenditures.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of liquidity.
Cash Flow

Cash flows for 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
<td>$1,742</td>
<td>$2,618</td>
<td>$3,049</td>
</tr>
<tr>
<td>Cash Flows from (Used for):</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating Activities</td>
<td>219,101</td>
<td>164,626</td>
<td>210,136</td>
</tr>
<tr>
<td>Investing Activities</td>
<td>(692,345)</td>
<td>(503,819)</td>
<td>(323,193)</td>
</tr>
<tr>
<td>Financing Activities</td>
<td>473,412</td>
<td>338,317</td>
<td>112,626</td>
</tr>
<tr>
<td>Net Increase (Decrease) in Cash and Cash Equivalents</td>
<td>168</td>
<td>(876)</td>
<td>(431)</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
<td>$1,910</td>
<td>$1,742</td>
<td>$2,618</td>
</tr>
</tbody>
</table>

Operating Activities

Net Cash Flows from Operating Activities were $219 million in 2008. SWEPCo produced Net Income of $93 million during the period and had a noncash expense item of $145 million for Depreciation and Amortization and $62 million for Deferred Income Taxes. SWEPCo recorded a Provision for Revenue Refund of $54 million to its customers for off-system sales margins to be received from the AEP East companies as ordered by the FERC related to the SIA. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $87 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel cost. The $52 million change in Accounts Receivable, Net was primarily the result of the refund to be received from the AEP East companies related to the SIA. The $25 million outflow from Fuel, Materials and Supplies was primarily due to higher coal and fuel related costs.

Net Cash Flows from Operating Activities were $165 million in 2007. SWEPCo produced Net Income of $66 million during the period and had noncash expense items of $139 million for Depreciation and Amortization and $17 million related to the Provision for Fuel Disallowance recorded as the result of an ALJ ruling in SWEPCo’s Texas fuel reconciliation proceeding. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $37 million outflow from Accounts Payable is primarily due to the timing of fuel payments at the end of the year. The $26 million outflow from Fuel Over/Under-Recovery, Net is due to under recovery of higher fuel costs. The $23 million inflow from Margin Deposits was due to decreased trading-related deposits resulting from normal trading activities. The $21 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company.

Net Cash Flows from Operating Activities were $210 million in 2006. SWEPCo produced Net Income of $92 million during the period and had a noncash expense item of $132 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $74 million inflow related to Fuel Over/Under-Recovery, Net was primarily due to the new fuel surcharges effective December 2005 in the Arkansas service territory and in January 2006 in the Texas service territory. The $67 million inflow from Accounts Payable was the result of higher energy purchases. The $52 million outflow from Accounts Receivable, Net was primarily due to an increase in the proportionate share of trading and marketing Accounts Receivable as a result of changes in the CSW Operating Agreement and the SIA. The $40 million outflow from Fuel, Materials and Supplies was the result of increased fuel purchases. The $24 million outflow for Margin Deposits was due to increased trading-related deposits resulting from the amended SIA.
Investing Activities

Net Cash Flows Used for Investing Activities during 2008, 2007 and 2006 were $692 million, $504 million and $323 million, respectively. The cash outflows during 2008, 2007 and 2006 were comprised primarily of Construction Expenditures related to the construction of the Turk Plant, Mattison Plant and Stall Unit, which are all new generation facilities. The cash outflows during 2006 were also comprised of Construction Expenditures related to projects for improved transmission and distribution service reliability.

Financing Activities

Net Cash Flows from Financing Activities were $473 million during 2008. During the year, SWEPCo issued $400 million of Senior Unsecured Notes. SWEPCo received a Capital Contribution from Parent of $200 million. SWEPCo retired $160 million of Nonaffiliated Long-term Debt.

Net Cash Flows from Financing Activities were $338 million during 2007. SWEPCo issued $550 million of Senior Unsecured Notes and $25 million in Notes Payable. SWEPCo retired $90 million of First Mortgage Bonds. SWEPCo reduced its borrowings from the Utility Money Pool by $187 million and received a Capital Contribution from Parent of $85 million. SWEPCo also had a net decrease in short-term debt of $17 million.

Net Cash Flows from Financing Activities were $113 million during 2006. SWEPCo had a net increase of $161 million in borrowings from the Utility Money Pool during the fourth quarter. SWEPCo refinanced (retired and issued) $82 million of Pollution Control Bonds and retired $15 million of long-term debt. SWEPCo had a net increase in short-term debt of $16 million. In addition, SWEPCo paid $40 million in common stock dividends.
Summary Obligation Information

SWEPCo’s contractual cash obligations include amounts reported on SWEPCo’s Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes SWEPCo’s contractual cash obligations at December 31, 2008:

<table>
<thead>
<tr>
<th>Contractual Cash Obligations</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates (a)</td>
<td>$ 2.5</td>
<td>-</td>
<td>-</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>Short-term Debt (b)</td>
<td>7.2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Interest on Fixed Rate Portion of Long-term Debt (c)</td>
<td>83.8</td>
<td>159.1</td>
<td>151.6</td>
<td>328.0</td>
<td>722.5</td>
</tr>
<tr>
<td>Fixed Rate Portion of Long-term Debt (d)</td>
<td>4.4</td>
<td>97.0</td>
<td>20.0</td>
<td>1,306.7</td>
<td>1,428.1</td>
</tr>
<tr>
<td>Variable Rate Portion of Long-term Debt (e)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>53.5</td>
<td>53.5</td>
</tr>
<tr>
<td>Capital Lease Obligations (f)</td>
<td>17.9</td>
<td>36.0</td>
<td>18.1</td>
<td>75.0</td>
<td>147.0</td>
</tr>
<tr>
<td>Noncancelable Operating Leases (f)</td>
<td>8.6</td>
<td>37.1</td>
<td>3.5</td>
<td>15.2</td>
<td>64.4</td>
</tr>
<tr>
<td>Fuel Purchase Contracts (g)</td>
<td>379.9</td>
<td>670.4</td>
<td>523.4</td>
<td>2,607.7</td>
<td>4,181.4</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (h)</td>
<td>18.5</td>
<td>9.4</td>
<td>9.6</td>
<td>54.6</td>
<td>92.1</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (i)</td>
<td>313.4</td>
<td>554.8</td>
<td>278.7</td>
<td>-</td>
<td>1,146.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 836.2</strong></td>
<td><strong>$ 1,563.8</strong></td>
<td><strong>$ 1,004.9</strong></td>
<td><strong>$ 4,440.7</strong></td>
<td><strong>$ 7,845.6</strong></td>
</tr>
</tbody>
</table>

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Represents principal only excluding interest.
(c) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(d) See Note 14. Represents principal only excluding interest.
(e) See Note 14. Represents principal only excluding interest. Variable rate debt had an interest rate of 2.034% at December 31, 2008.
(f) See Note 13.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(i) Represents only capital assets that are contractual obligations.

SWEPCo’s FIN 48 liabilities of $10 million are not included above because SWEPCo cannot reasonably estimate the cash flows by period.

AEP’s minimum pension funding requirements are not included in the above table. As of December 31, 2008, the decline in pension asset values will not require AEP to make a contribution in 2009. AEP will need to make minimum contributions to the pension plan of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

In addition to the amounts disclosed in the contractual cash obligations table above, SWEPCo makes additional commitments in the normal course of business. SWEPCo’s commitments outstanding at December 31, 2008 under these agreements are summarized in the table below:

<table>
<thead>
<tr>
<th>Other Commercial Commitments</th>
<th>Less Than 1 year</th>
<th>2-3 years</th>
<th>4-5 years</th>
<th>After 5 years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standby Letters of Credit (a)</td>
<td>$ 4.0</td>
<td>-</td>
<td>-</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>Guarantees of the Performance ofOutside Parties (b)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>65.0</td>
<td>65.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 4.0</strong></td>
<td><strong>$ -</strong></td>
<td><strong>$ -</strong></td>
<td><strong>$ 65.0</strong></td>
<td><strong>$ 69.0</strong></td>
</tr>
</tbody>
</table>

(a) SWEPCo has issued standby letters of credit. These letters of credit cover insurance programs, security deposits and debt service reserves. All of these letters of credit were issued in SWEPCo’s ordinary course of business. The maximum future payments of these letters of credit are $4 million maturing in December 2009. There is no recourse to third parties in the event these letters of credit are drawn. See “Letters of Credit” section of Note 6.
(b) See “Guarantees of Third-Party Obligations” section of Note 6.
**Significant Factors**

**New Generation**

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for additional discussion of relevant factors.

**Litigation and Regulatory Activity**

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect SWEPCo’s net income, financial condition and cash flows.

**Critical Accounting Estimates**

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

**Adoption of New Accounting Pronouncements**

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page I-1 for a discussion of adoption of new accounting pronouncements.
QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section. The following tables provide information about AEP’s risk management activities’ effect on SWEPCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in SWEPCo’s Consolidated Balance Sheet as of December 31, 2008 and the reasons for changes in total MTM value as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet
December 31, 2008
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>MTM Risk Management Contracts</th>
<th>Cash Flow &amp; Fair Value Hedges</th>
<th>DETM Assignment (a)</th>
<th>Collateral Deposits</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets</td>
<td>$8,185</td>
<td>$8,185</td>
<td>-</td>
<td>-</td>
<td>$8,185</td>
</tr>
<tr>
<td>Noncurrent Assets</td>
<td>1,473</td>
<td>27</td>
<td>-</td>
<td>-</td>
<td>1,500</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Assets</strong></td>
<td><strong>9,658</strong></td>
<td><strong>27</strong></td>
<td>-</td>
<td>-</td>
<td><strong>9,685</strong></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>(6,583)</td>
<td>(185)</td>
<td>(91)</td>
<td>124</td>
<td>(6,735)</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>(432)</td>
<td>-</td>
<td>(84)</td>
<td>-</td>
<td>(516)</td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Liabilities</strong></td>
<td><strong>(7,015)</strong></td>
<td><strong>(185)</strong></td>
<td><strong>(175)</strong></td>
<td><strong>124</strong></td>
<td><strong>(7,251)</strong></td>
</tr>
<tr>
<td><strong>Total MTM Derivative Contract Net Assets (Liabilities)</strong></td>
<td>$2,643</td>
<td>$(158)</td>
<td>$(175)</td>
<td>$124</td>
<td>$2,434</td>
</tr>
</tbody>
</table>

(a) See “Natural Gas Contracts with DETM” section of Note 15.
MTM Risk Management Contract Net Assets
Year Ended December 31, 2008
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2007 $ 8,131
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period (7,317)
Fair Value of New Contracts at Inception When Entered During the Period (a) -
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period -
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b) 73
Changes in Fair Value Due to Market Fluctuations During the Period (c) 475
Changes in Fair Value Allocated to Regulated Jurisdictions (d) 1,281
Total MTM Risk Management Contract Net Assets 2,643
Net Cash Flow & Fair Value Hedge Contracts (158)
DETM Assignment (e) (175)
Collateral Deposits 124
Ending Net Risk Management Assets (Liabilities) at December 31, 2008 $ 2,434

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b) Represents the impact of applying AEP’s credit risk when measuring the fair value of derivative liabilities according to SFAS 157.

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

(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

(e) See “Natural Gas Contracts with DETM” section of Note 15.
Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The following table presents the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash:

<table>
<thead>
<tr>
<th>Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets</th>
<th>Fair Value of Contracts as of December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
</tr>
<tr>
<td>Level 1 (a)</td>
<td>$ (435)</td>
</tr>
<tr>
<td>Level 2 (b)</td>
<td>2,042</td>
</tr>
<tr>
<td>Level 3 (c)</td>
<td>(5)</td>
</tr>
<tr>
<td>Total</td>
<td>$ 1,602</td>
</tr>
</tbody>
</table>

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.

(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

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

Management uses interest rate derivative transactions to manage interest rate risk exposure on anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate exposure.

Management uses foreign currency derivatives to lock in prices on certain forecasted transactions denominated in foreign currencies where deemed necessary, and designates qualifying instruments as cash flow hedges. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on SWEPCo’s Consolidated Balance Sheets and the reasons for the changes from December 31, 2007 to December 31, 2008. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity

Year Ended December 31, 2008 (in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Interest Rate</th>
<th>Foreign Currency</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beginning Balance in AOCI December 31, 2007</td>
<td>$ (6,650)</td>
<td>$ 629</td>
<td>$ (6,021)</td>
</tr>
<tr>
<td>Changes in Fair Value</td>
<td>-</td>
<td>(187)</td>
<td>(187)</td>
</tr>
<tr>
<td>Reclassifications from AOCI for Cash Flow Hedges Settled</td>
<td>828</td>
<td>(544)</td>
<td>284</td>
</tr>
<tr>
<td>Ending Balance in AOCI December 31, 2008</td>
<td>$ (5,822)</td>
<td>$ (102)</td>
<td>$ (5,924)</td>
</tr>
</tbody>
</table>

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $829 thousand loss.
Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2008, a near term typical change in commodity prices is not expected to have a material effect on net income, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR for the years ended:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008 (in thousands)</th>
<th>December 31, 2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>End</td>
<td>$8</td>
<td>$17</td>
</tr>
<tr>
<td>High</td>
<td>$220</td>
<td>$245</td>
</tr>
<tr>
<td>Average</td>
<td>$62</td>
<td>$75</td>
</tr>
<tr>
<td>Low</td>
<td>$8</td>
<td>$7</td>
</tr>
</tbody>
</table>

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management’s backtesting results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes SWEPCo’s VaR calculation is conservative.

As SWEPCo’s VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand SWEPCo’s exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translated into the largest potential mark-to-market loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which SWEPCo’s interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2009, the estimated EaR on SWEPCo’s debt portfolio is $8.8 million.
SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED STATEMENTS OF INCOME  
For the Years Ended December 31, 2008, 2007 and 2006  
(in thousands)  

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REVENUES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Generation, Transmission and Distribution</td>
<td>$1,458,027</td>
<td>$1,393,582</td>
<td>$1,348,673</td>
</tr>
<tr>
<td>Sales to AEP Affiliates</td>
<td>50,842</td>
<td>53,102</td>
<td>42,445</td>
</tr>
<tr>
<td>Lignite Revenues – Nonaffiliated</td>
<td>44,366</td>
<td>35,031</td>
<td>37,980</td>
</tr>
<tr>
<td>Other</td>
<td>1,527</td>
<td>1,747</td>
<td>2,741</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,554,762</td>
<td>1,483,462</td>
<td>1,431,839</td>
</tr>
<tr>
<td><strong>EXPENSES</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel and Other Consumables Used for Electric Generation</td>
<td>523,361</td>
<td>515,565</td>
<td>471,418</td>
</tr>
<tr>
<td>Purchased Electricity for Resale</td>
<td>164,466</td>
<td>209,754</td>
<td>175,124</td>
</tr>
<tr>
<td>Purchased Electricity from AEP Affiliates</td>
<td>118,773</td>
<td>72,895</td>
<td>74,458</td>
</tr>
<tr>
<td>Other Operation</td>
<td>260,186</td>
<td>234,726</td>
<td>224,750</td>
</tr>
<tr>
<td>Maintenance</td>
<td>111,273</td>
<td>110,270</td>
<td>100,962</td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>145,011</td>
<td>139,241</td>
<td>132,261</td>
</tr>
<tr>
<td>Taxes Other Than Income Taxes</td>
<td>59,047</td>
<td>66,309</td>
<td>63,248</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,382,117</td>
<td>1,348,760</td>
<td>1,242,221</td>
</tr>
<tr>
<td><strong>OPERATING INCOME</strong></td>
<td>172,645</td>
<td>134,702</td>
<td>189,618</td>
</tr>
<tr>
<td><strong>Other Income (Expense):</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest Income</td>
<td>35,086</td>
<td>3,007</td>
<td>2,582</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>14,908</td>
<td>10,243</td>
<td>1,302</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(93,150)</td>
<td>(60,619)</td>
<td>(55,213)</td>
</tr>
<tr>
<td><strong>INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS</strong></td>
<td>129,489</td>
<td>87,333</td>
<td>138,289</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>33,041</td>
<td>17,561</td>
<td>43,697</td>
</tr>
<tr>
<td>Minority Interest Expense</td>
<td>3,691</td>
<td>3,507</td>
<td>2,868</td>
</tr>
<tr>
<td>Equity Earnings of Unconsolidated Subsidiaries</td>
<td>(3)</td>
<td>(1)</td>
<td>(1)</td>
</tr>
<tr>
<td><strong>NET INCOME</strong></td>
<td>92,754</td>
<td>66,264</td>
<td>91,723</td>
</tr>
<tr>
<td>Preferred Stock Dividend Requirements</td>
<td>229</td>
<td>229</td>
<td>229</td>
</tr>
<tr>
<td><strong>EARNINGS APPLICABLE TO COMMON STOCK</strong></td>
<td>$92,525</td>
<td>$66,035</td>
<td>$91,494</td>
</tr>
</tbody>
</table>

The common stock of SWEPCo is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>Common Stock</th>
<th>Paid-in Capital</th>
<th>Retained Earnings</th>
<th>Accumulated Other Comprehensive Income (Loss)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>DECEMBER 31, 2005</td>
<td>$ 135,660</td>
<td>$ 245,003</td>
<td>$ 407,844</td>
<td>$ (6,129)</td>
<td>$ 782,378</td>
</tr>
</tbody>
</table>

Common Stock Dividends      (40,000)   (40,000)  
Preferred Stock Dividends   (229)       (229)  
TOTAL                        |               |                 |                   |                                               | 742,149 |

COMPREHENSIVE INCOME
Other Comprehensive Income (Loss), Net of Taxes:
Cash Flow Hedges, Net of Tax of $515       (558)       (558)  
Minimum Pension Liability, Net of Tax of $35       65         65  
NET INCOME                                    91,723       91,723  
TOTAL COMPREHENSIVE INCOME                   91,230       91,230  
Minimum Pension Liability Elimination, Net of Tax of $114       212         212  
SFAS 158 Adoption, Net of Tax of $6,671       (12,389)    (12,389)  
DECEMBER 31, 2006                            135,660       245,003       459,338         (18,799)        821,202  
FIN 48 Adoption, Net of Tax       (1,642)       (1,642)  
Capital Contribution from Parent   85,000       85,000  
Preferred Stock Dividends     (229)       (229)  
TOTAL                           |               |                 |                   |                                               | 904,331 |

COMPREHENSIVE INCOME
Other Comprehensive Income, Net of Taxes:
Cash Flow Hedges, Net of Tax of $210       389         389  
Pension and OPEB Funded Status, Net of Tax of $1,061       1,971       1,971  
NET INCOME                                    66,264       66,264  
TOTAL COMPREHENSIVE INCOME                   68,624       68,624  
DECEMBER 31, 2007                            135,660       330,003       523,731         (16,439)       972,955  
EITF 06-10 Adoption, Net of Tax of $622       (1,156)      (1,156)  
SFAS 157 Adoption, Net of Tax of $6       10           10  
Capital Contribution from Parent   200,000       200,000  
Preferred Stock Dividends     (229)       (229)  
TOTAL                           |               |                 |                   |                                               | 1,171,580 |

COMPREHENSIVE INCOME
Other Comprehensive Income (Loss), Net of Taxes:
Cash Flow Hedges, Net of Tax of $52         97           97  
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $507 941       941  
Pension and OPEB Funded Status, Net of Tax of $9,003       (16,719)    (16,719)  
NET INCOME                                    92,754       92,754  
TOTAL COMPREHENSIVE INCOME                   77,073       77,073  
DECEMBER 31, 2008                            $ 135,660    $ 530,003       $ 615,110         $ (32,120)       $ 1,248,653  

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
# Southwestern Electric Power Company Consolidated Balance Sheets

## Assets

### December 31, 2008 and 2007

**Editors Note:**

*Data represented as in thousands (in thousands).

<table>
<thead>
<tr>
<th>Category</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Current Assets</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>$1,910</td>
<td>$1,742</td>
</tr>
<tr>
<td>Accounts Receivable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customers</td>
<td>53,506</td>
<td>91,379</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>121,928</td>
<td>33,196</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>12,052</td>
<td>10,544</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts</td>
<td>(135)</td>
<td>(143)</td>
</tr>
<tr>
<td>Total Accounts Receivable</td>
<td>187,351</td>
<td>134,976</td>
</tr>
<tr>
<td>Fuel</td>
<td>100,018</td>
<td>75,662</td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>49,724</td>
<td>48,673</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>8,185</td>
<td>39,850</td>
</tr>
<tr>
<td>Regulatory Asset for Under-Recovered Fuel Costs</td>
<td>75,006</td>
<td>5,859</td>
</tr>
<tr>
<td>Margin Deposits</td>
<td>1,470</td>
<td>10,650</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>18,677</td>
<td>28,147</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>442,341</td>
<td>345,559</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Category</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Property, Plant and Equipment</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>1,808,482</td>
<td>1,743,198</td>
</tr>
<tr>
<td>Transmission</td>
<td>786,731</td>
<td>737,975</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,400,952</td>
<td>1,312,746</td>
</tr>
<tr>
<td>Other</td>
<td>711,260</td>
<td>631,765</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>869,103</td>
<td>451,228</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>5,576,528</td>
<td>4,876,912</td>
</tr>
<tr>
<td>Accumulated Depreciation and Amortization</td>
<td>2,014,154</td>
<td>1,939,044</td>
</tr>
<tr>
<td><strong>Total - Net</strong></td>
<td>3,562,374</td>
<td>2,937,868</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Category</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Other Noncurrent Assets</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulatory Assets</td>
<td>210,174</td>
<td>133,617</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>1,500</td>
<td>4,073</td>
</tr>
<tr>
<td>Deferred Charges and Other</td>
<td>36,696</td>
<td>67,269</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>248,370</td>
<td>204,959</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Category</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Assets</strong></td>
<td>$4,253,085</td>
<td>$3,488,386</td>
</tr>
</tbody>
</table>

*See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.*
### CURRENT LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advances from Affiliates</td>
<td>$2,526</td>
<td>$1,565</td>
</tr>
<tr>
<td>Accounts Payable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>133,538</td>
<td>152,305</td>
</tr>
<tr>
<td>Affiliated Companies</td>
<td>51,040</td>
<td>51,767</td>
</tr>
<tr>
<td>Short-term Debt – Nonaffiliated</td>
<td>7,172</td>
<td>285</td>
</tr>
<tr>
<td>Long-term Debt Due Within One Year – Nonaffiliated</td>
<td>4,406</td>
<td>5,906</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>6,735</td>
<td>32,629</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>35,622</td>
<td>37,473</td>
</tr>
<tr>
<td>Accrued Taxes</td>
<td>33,744</td>
<td>26,494</td>
</tr>
<tr>
<td>Accrued Interest</td>
<td>36,647</td>
<td>17,035</td>
</tr>
<tr>
<td>Regulatory Liability for Over-Recovered Fuel Costs</td>
<td>5,162</td>
<td>22,879</td>
</tr>
<tr>
<td>Provision for Revenue Refund</td>
<td>54,100</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>97,373</td>
<td>59,519</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>468,065</td>
<td>407,857</td>
</tr>
</tbody>
</table>

### NONCURRENT LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term Debt – Nonaffiliated</td>
<td>1,423,743</td>
<td>1,141,311</td>
</tr>
<tr>
<td>Long-term Debt – Affiliated</td>
<td>50,000</td>
<td>50,000</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>516</td>
<td>3,334</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>403,125</td>
<td>361,806</td>
</tr>
<tr>
<td>Regulatory Liabilities and Deferred Investment Tax Credits</td>
<td>335,749</td>
<td>334,014</td>
</tr>
<tr>
<td>Asset Retirement Obligations</td>
<td>53,433</td>
<td>49,828</td>
</tr>
<tr>
<td>Employment Benefits and Pension Obligations</td>
<td>117,772</td>
<td>32,374</td>
</tr>
<tr>
<td>Deferred Credits and Other</td>
<td>147,056</td>
<td>128,523</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>2,531,394</td>
<td>2,101,190</td>
</tr>
</tbody>
</table>

### TOTAL LIABILITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Liabilities</td>
<td>2,999,459</td>
<td>2,509,047</td>
</tr>
<tr>
<td>Minority Interest</td>
<td>276</td>
<td>1,687</td>
</tr>
<tr>
<td>Cumulative Preferred Stock Not Subject to Mandatory Redemption</td>
<td>4,697</td>
<td>4,697</td>
</tr>
<tr>
<td>Commitments and Contingencies (Note 6)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### COMMON SHAREHOLDER’S EQUITY

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Stock – Par Value – $18 Per Share:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Authorized – 7,600,000 Shares</td>
<td>135,660</td>
<td>135,660</td>
</tr>
<tr>
<td>Outstanding – 7,536,640 Shares</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Paid-in Capital</td>
<td>530,003</td>
<td>330,003</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>615,110</td>
<td>523,731</td>
</tr>
<tr>
<td>Accumulated Other Comprehensive Income (Loss)</td>
<td>(32,120)</td>
<td>(16,439)</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>1,248,653</td>
<td>972,955</td>
</tr>
</tbody>
</table>

### TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY

<table>
<thead>
<tr>
<th>Description</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Liabilities and Shareholders’ Equity</td>
<td>$4,253,085</td>
<td>$3,488,386</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

<table>
<thead>
<tr>
<th>OPERATING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$92,754</td>
<td>$66,264</td>
<td>$91,723</td>
</tr>
<tr>
<td>Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation and Amortization</td>
<td>145,011</td>
<td>139,241</td>
<td>132,261</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>62,060</td>
<td>(21,935)</td>
<td>(23,667)</td>
</tr>
<tr>
<td>Provision for Fuel Disallowance</td>
<td>-</td>
<td>17,011</td>
<td>-</td>
</tr>
<tr>
<td>Provision for Revenue Refund</td>
<td>54,100</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Allowance for Equity Funds Used During Construction</td>
<td>14,908</td>
<td>(10,243)</td>
<td>(1,320)</td>
</tr>
<tr>
<td>Mark-to-Market of Risk Management Contracts</td>
<td>5,294</td>
<td>12,383</td>
<td>(17,516)</td>
</tr>
<tr>
<td>Change in Other Noncurrent Assets</td>
<td>27,121</td>
<td>23,530</td>
<td>31,204</td>
</tr>
<tr>
<td>Change in Other Noncurrent Liabilities</td>
<td>(9,107)</td>
<td>(21,656)</td>
<td>(30,580)</td>
</tr>
<tr>
<td>Net Cash Flows from Operating Activities</td>
<td>219,101</td>
<td>164,626</td>
<td>210,136</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>INVESTING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Expenditures</td>
<td>(692,162)</td>
<td>(504,645)</td>
<td>(323,332)</td>
</tr>
<tr>
<td>Change in Other Cash Deposits</td>
<td>(157)</td>
<td>(122)</td>
<td>(120)</td>
</tr>
<tr>
<td>Acquisitions of Assets</td>
<td>(1,133)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Proceeds from Sales of Assets</td>
<td>1,107</td>
<td>948</td>
<td>259</td>
</tr>
<tr>
<td>Net Cash Flows Used for Investing Activities</td>
<td>(692,345)</td>
<td>(503,819)</td>
<td>(323,193)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FINANCING ACTIVITIES</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Contribution from Parent</td>
<td>200,000</td>
<td>85,000</td>
<td>-</td>
</tr>
<tr>
<td>Issuance of Long-term Debt – Nonaffiliated</td>
<td>437,042</td>
<td>569,078</td>
<td>80,593</td>
</tr>
<tr>
<td>Change in Short-term Debt, Net – Nonaffiliated</td>
<td>6,887</td>
<td>16,858</td>
<td>15,749</td>
</tr>
<tr>
<td>Change in Advances from Affiliates, Net</td>
<td>961</td>
<td>187,400</td>
<td>160,755</td>
</tr>
<tr>
<td>Retirement of Long-term Debt – Nonaffiliated</td>
<td>160,444</td>
<td>102,312</td>
<td>97,455</td>
</tr>
<tr>
<td>Retirement of Cumulative Preferred Stock</td>
<td>-</td>
<td>-</td>
<td>(3)</td>
</tr>
<tr>
<td>Principal Payments for Capital Lease Obligations</td>
<td>(11,511)</td>
<td>(8,962)</td>
<td>(6,784)</td>
</tr>
<tr>
<td>Dividends Paid on Common Stock</td>
<td>-</td>
<td>-</td>
<td>(40,000)</td>
</tr>
<tr>
<td>Dividends Paid on Cumulative Preferred Stock</td>
<td>(229)</td>
<td>(229)</td>
<td>(229)</td>
</tr>
<tr>
<td>Other</td>
<td>706</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Net Cash Flows from Financing Activities</td>
<td>473,412</td>
<td>338,317</td>
<td>112,626</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SUPPLEMENTARY INFORMATION</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Increase (Decrease) in Cash and Cash Equivalents</td>
<td>168</td>
<td>(876)</td>
<td>(431)</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at Beginning of Period</td>
<td>1,742</td>
<td>2,618</td>
<td>3,049</td>
</tr>
<tr>
<td>Cash and Cash Equivalents at End of Period</td>
<td>$1,910</td>
<td>$1,742</td>
<td>$2,618</td>
</tr>
</tbody>
</table>

See Notes to Financial Statements of Registrant Subsidiaries beginning on page H-1.
The notes to SWEPCo’s consolidated financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page H-1.

<table>
<thead>
<tr>
<th>Footnote Reference</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>Organization and Summary of Significant Accounting Policies</td>
<td>1</td>
</tr>
<tr>
<td>New Accounting Pronouncements and Extraordinary Item</td>
<td>2</td>
</tr>
<tr>
<td>Goodwill and Other Intangible Assets</td>
<td>3</td>
</tr>
<tr>
<td>Rate Matters</td>
<td>4</td>
</tr>
<tr>
<td>Effects of Regulation</td>
<td>5</td>
</tr>
<tr>
<td>Commitments, Guarantees and Contingencies</td>
<td>6</td>
</tr>
<tr>
<td>Benefit Plans</td>
<td>8</td>
</tr>
<tr>
<td>Business Segments</td>
<td>10</td>
</tr>
<tr>
<td>Derivatives, Hedging and Fair Value Measurements</td>
<td>11</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>12</td>
</tr>
<tr>
<td>Leases</td>
<td>13</td>
</tr>
<tr>
<td>Financing Activities</td>
<td>14</td>
</tr>
<tr>
<td>Related Party Transactions</td>
<td>15</td>
</tr>
<tr>
<td>Property, Plant and Equipment</td>
<td>16</td>
</tr>
<tr>
<td>Unaudited Quarterly Financial Information</td>
<td>17</td>
</tr>
</tbody>
</table>
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in common shareholder’s equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 8 to the consolidated financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009
MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Southwestern Electric Power Company Consolidated (SWEPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. SWEPCo’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of SWEPCo’s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management’s assessment, SWEPCo’s internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of SWEPCo’s registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by SWEPCo’s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit SWEPCo’s to provide only management’s report in this annual report.
NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1. Organization and Summary of Significant Accounting Policies  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
2. New Accounting Pronouncements and Extraordinary Item  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
3. Goodwill and Other Intangible Assets  SWEPCo
4. Rate Matters  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
5. Effects of Regulation  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
6. Commitments, Guarantees and Contingencies  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
7. Acquisition  CSPCo
8. Benefit Plans  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
9. Nuclear  I&M
10. Business Segments  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
11. Derivatives, Hedging and Fair Value Measurements  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
12. Income Taxes  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
13. Leases  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
14. Financing Activities  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
15. Related Party Transactions  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
16. Property, Plant and Equipment  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
17. Unaudited Quarterly Financial Information  APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
1. **ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**ORGANIZATION**

The principal business conducted by AEP’s Registrant Subsidiaries is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

The Registrant Subsidiaries engage in wholesale electricity marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies and SWEPCo conducts coal mining operations to fuel certain of its generation facilities.

**SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**Rates and Service Regulation**

The Registrant Subsidiaries’ rates are regulated by the FERC and state regulatory commissions in the nine state operating territories in which they operate. The state regulatory commissions approve retail rates and regulate the retail services and operations of the utility subsidiaries for the generation and supply of power, a majority of transmission energy delivery services and distribution services. The FERC regulates AEP’s, AEPSC’s and the Registrant Subsidiaries’ affiliated transactions, including AEPS intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility holding company subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliates statutes.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrant Subsidiaries’ wholesale power transactions are generally market-based. They are cost-based regulated when the Registrant Subsidiaries negotiate and file a cost-based contract with the FERC or the FERC determines that the Registrant Subsidiaries have “market power” in the region where the transaction occurs. The Registrant Subsidiaries enter into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. SWEPCo’s and PSO’s wholesale power transactions in the SPP region are cost-based due to SWEPCo and PSO having market power in the SPP region.

The FERC also regulates, on a cost basis, the Registrant Subsidiaries’ wholesale transmission service and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo’s and OPCo’s retail rates in Ohio, APCo’s retail rates in Virginia and I&M’s retail rates in Michigan are unbundled. CSPCo’s and OPCo’s retail transmission rates are based on the FERC’s Open Access Transmission Tariff (OATT) rates that are cost-based. Although APCo’s retail rates in Virginia and I&M’s retail rates in Michigan are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Starting in 2009, APCo may file, and the Virginia SCC shall approve, a rate adjustment clause that passes through charges associated with the FERC’s OATT rates to APCo’s Virginia retail customers. Bundled retail transmission rates are regulated, on a cost basis, by the state regulatory commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Equalization Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the Registrant Subsidiaries that are parties to each agreement.
The state regulatory commissions regulate all of the retail public utility services/operations (generation/power supply, transmission and distribution operations) and rates except in Ohio. The retail generation/power supply operations and rates for CSPCo and OPCo in Ohio are no longer cost-based regulated. These rates were subject to RSPs through December 31, 2008. The PUCO extended these rates until they issue a ruling on the ESPs or the end of the February 2009 billing cycle, whichever comes first. The ESP rates are under recently enacted legislation, which continues the concept of increasing rates over time to approach market rates. In 2007, the Virginia legislation ended a transition to market-based rates and returned APCo to cost-based regulation. See Note 4 for further information of restructuring legislation and its effects on AEP in Ohio and Michigan.

Both the FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

**Principles of Consolidation**

The consolidated financial statements for APCo, CSPCo and I&M include the Registrant Subsidiary and its wholly-owned subsidiaries. The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Sabine (a substantially-controlled variable interest entity (VIE)). The consolidated financial statements for OPCo include the Registrant Subsidiary and JMG (a substantially-controlled VIE). Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled and which the subsidiary is not the primary beneficiary of the entity, that are 50% or less owned are accounted for using the equity method of accounting and are reported as Deferred Charges and Other on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. For years, CSPCo, OPCo, PSO and SWEPCo have had ownership interests in generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the income statements and the assets and liabilities are reflected in the balance sheets. See “Variable Interest Entities” section of Note 15.

**Accounting for the Effects of Cost-Based Regulation**

As cost-based rate-regulated electric public utility companies, the Registrant Subsidiaries’ financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required restructuring and a transition to customer choice and market-based rates, certain affected Registrant Subsidiaries discontinued the application of SFAS 71, regulatory accounting, for the generation portion of their business as follows: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000 and the Texas portion of SWEPCo in September 1999. In 2007, the Virginia legislature amended its restructuring legislation to provide for the re-regulation of generation and supply business and rates on a cost basis. SFAS 101, “Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71” requires the recognition of an impairment of stranded regulatory assets and stranded plants costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities pursuant to SFAS 71. Such impairments and adjustments arising from the discontinuance or reapplication of SFAS 71 are classified by SFAS 101 as an extraordinary item. Consistent with SFAS 101, APCo recorded an extraordinary reduction in earnings and shareholder’s equity from the reapplication of SFAS 71 regulatory accounting in 2007 resulting from the re-regulation of APCo’s generation and supply rates on a cost basis.

**Use of Estimates**

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management’s evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.
Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and equity investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and Texas, effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, “Capitalization of Interest Costs.”

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for environmental construction expenditures.

Inventory

Fossil fuel inventories are carried at average cost for APCo, I&M, PSO and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. Materials and supplies inventories are carried at average cost.
Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, the Registrant Subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable through purchase agreements with CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo’s accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,” allowing the receivables to be removed from the company’s balance sheet (see “Sale of Receivables - AEP Credit” section of Note 14).

Concentrations of Credit Risk and Significant Customers

The Registrant Subsidiaries do not have any significant customers that comprise 10% or more of their Operating Revenues as of December 31, 2008.

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying registrant financial statements.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the amortization of nuclear fuel costs which are computed primarily on the units-of-production method. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator’s review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit the Registrant Subsidiaries’ fuel cost calculations and deferrals. When a fuel cost disallowance becomes probable, the Registrant Subsidiaries adjust their deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated.

In general, changes in fuel costs in Indiana (beginning July 1, 2007) and Michigan for I&M, Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia and West Virginia (beginning July 1, 2006) for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All of the profits from off-system sales are shared with customers through fuel clauses in West Virginia (beginning in July 1, 2006). A portion of profits from off-system sales are shared with customers through fuel clauses in Texas, Oklahoma, Louisiana, Arkansas, Virginia (beginning September 1, 2007) and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions (prior to July 1, 2007 in Indiana and prior to July 1, 2006 in West Virginia), where fuel clauses were capped, frozen or suspended for a period of years, fuel costs impacted earnings.
Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, the Registrant Subsidiaries record them as assets on the balance sheet. The Registrant Subsidiaries test for probability of recovery at each balance sheet date or whenever new events occur. Examples include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the Registrant Subsidiaries write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

The Registrant Subsidiaries recognize revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrant Subsidiaries recognize the revenues in the financial statements upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to their customers. These power sales and purchases are reported on a net basis as revenues in the financial statements. Other RTOs in which the Registrant Subsidiaries operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases including those from RTOs that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale in the financial statements.

In general, the Registrant Subsidiaries record expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio for CSPCo and OPCo and Texas for SWEPCo. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in AEP’s west zone where PSO and SWEPCo are short capacity, they recognize as revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period before settlement. If the contract results in the physical delivery of power from a RTO or any other counterparty, PSO and SWEPCo reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Energy for Resale. If the contract does not result in physical delivery, PSO and SWEPCo reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as revenues in the financial statements on a net basis.
Energy Marketing and Risk Management Activities

AEPSC, on behalf of the Registrant Subsidiaries and KPCo, engages in wholesale electricity, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Certain energy marketing and risk management transactions are with RTOs.

The Registrant Subsidiaries recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. The Registrant Subsidiaries use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. For CSPCo and OPCo, the unrealized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in revenues on a net basis on the respective income statements. For APCo, I&M, PSO and a portion of SWEPCo, who are subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

The Registrant Subsidiaries include realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis on their income statements. Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivatives transactions are designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge). The Registrant Subsidiaries initially record the effective portion of the cash flow hedge’s gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrant Subsidiaries subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their income statements. For CSPCo and OPCo, the ineffective portion of the gain or loss is recognized in revenues or expense in the financial statements immediately. APCo, I&M, PSO, and a portion of SWEPCo, who are subject to cost-based regulation, defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See “Cash Flow Hedging Strategies” section of Note 11.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit’s refueling outage and lasting until the end of the month in which the same unit’s next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

The Registrant Subsidiaries expense maintenance costs as incurred. If it becomes probable that the Registrant Subsidiaries will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expense of those maintenance costs with their recovery in cost-based regulated revenues. PSO defers distribution tree trimming costs above the level included in base rates and amortizes the costs commensurate with recovery through a rate rider in Oklahoma. PSO also amortizes deferred ice storm costs commensurate with their recovery through a rate rider.

Income Taxes and Investment Tax Credits

The Registrant Subsidiaries use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.
Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

The Registrant Subsidiaries account for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48 beginning January 1, 2007, the Registrant Subsidiaries classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

Excise Taxes

The Registrant Subsidiaries, as agents for some state and local governments, collect from customers certain excise taxes levied by those state or local governments on customers. The Registrant Subsidiaries do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. The Registrant Subsidiaries report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain Registrant Subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

Goodwill and Intangible Assets

SWEPCo is the only Registrant Subsidiary with an intangible asset with a finite life. SWEPCo amortizes the asset over its estimated life to its residual value (see Note 3). The Registrant Subsidiaries have no recorded goodwill or intangible assets with indefinite lives as of December 31, 2008 and 2007.

Emission Allowances

The Registrant Subsidiaries record emission allowances at cost, including the annual SO2 and NOx emission allowance entitlements received at no cost from the Federal EPA and States. They follow the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies for all of the Registrant Subsidiaries except CSPCo who reflects allowances in Emission Allowances. Allowances with expected consumption beyond one year are included in Other Noncurrent Assets – Deferred Charges and Other. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Current Assets – Prepayments and Other for all the Registrant Subsidiaries except CSPCo, who reflects allowances held for speculation in Emission Allowances. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and the Registrant Subsidiaries’ revenue optimization strategy for their operations. The net margin on sales of emission allowances affects the determination of deferred fuel costs and the amortization of regulatory assets for certain jurisdictions.
**Nuclear Trust Funds**

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its Consolidated Balance Sheet. I&M records these securities at market value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments are considered realized losses as I&M does not make specific investment decisions regarding the assets held in trusts. They reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See Note 9 for additional discussion of nuclear matters.

**Comprehensive Income (Loss)**

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).
Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder’s equity section. AOCI for the Registrant Subsidiaries as of December 31, 2008 and 2007 is shown in the following table:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2008 (in thousands)</th>
<th>December 31, 2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash Flow Hedges, Net of Tax</td>
<td></td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td>$(5,392)</td>
<td>$(5,944)</td>
</tr>
<tr>
<td>CSPCo</td>
<td>1,531</td>
<td>(650)</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(9,039)</td>
<td>(12,151)</td>
</tr>
<tr>
<td>OPCo</td>
<td>3,650</td>
<td>1,157</td>
</tr>
<tr>
<td>PSO</td>
<td>(704)</td>
<td>(887)</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>(5,924)</td>
<td>(6,021)</td>
</tr>
<tr>
<td>Amortization of Pension and OPEB Deferred Costs, Net of Tax</td>
<td>$3,333</td>
<td>$-</td>
</tr>
<tr>
<td>APCo</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CSPCo</td>
<td>1,128</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>441</td>
<td>-</td>
</tr>
<tr>
<td>OPCo</td>
<td>2,813</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>941</td>
<td>-</td>
</tr>
<tr>
<td>Pension and OPEB Funded Status, Net of Tax</td>
<td>$(58,166)</td>
<td>$(29,243)</td>
</tr>
<tr>
<td>APCo</td>
<td>$(53,684)</td>
<td>(18,144)</td>
</tr>
<tr>
<td>CSPCo</td>
<td>(13,096)</td>
<td>(3,524)</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(140,321)</td>
<td>(37,698)</td>
</tr>
<tr>
<td>OPCo</td>
<td>(27,137)</td>
<td>(10,418)</td>
</tr>
</tbody>
</table>

Earnings Per Share (EPS)

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo are wholly-owned subsidiaries of AEP. Therefore, none are required to report EPS.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. See “FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on the Registrant Subsidiaries’ previously reported net income or changes in shareholders’ equity.
NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries’ business. The follow represents a summary of final pronouncements that management has determined relate to the Registrant Subsidiaries’ operations.

Pronouncements Adopted in 2008

The following standards were effective during 2008. Consequently, the financial statements and footnotes reflect their impact.

**SFAS 157 “Fair Value Measurements” (SFAS 157)**

The Registrant Subsidiaries partially adopted SFAS 157 effective January 1, 2008. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures.

In February 2008, the FASB issued FSP SFAS 157-1 “Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13” (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 “Accounting for Leases” (SFAS 13) and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. SFAS 157-1 was effective upon issuance and had an immaterial impact on the financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 “Effective Date of FASB Statement No. 157” (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The Registrant Subsidiaries fully adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had an immaterial impact on the financial statements.

In October 2008, the FASB issued FSP SFAS 157-3 “Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active” which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on the financial statements.

See “SFAS 157 Fair Value Measurements” Section of Note 11 for further information.

**SFAS 159 “The Fair Value Option for Financial Assets and Financial Liabilities” (SFAS 159)**

The FASB permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

The Registrant Subsidiaries adopted SFAS 159 effective January 1, 2008. At adoption, the Registrant Subsidiaries did not elect the fair value option for any assets or liabilities.

**SFAS 162 “The Hierarchy of Generally Accepted Accounting Principles” (SFAS 162)**

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

The Registrant Subsidiaries adopted SFAS 162 in the fourth quarter of 2008. The adoption of this standard had no impact on the financial statements.
In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) retrospective application to all prior periods. The Registrant Subsidiaries adopted EITF 06-10 effective January 1, 2008. The impact of this standard was an unfavorable cumulative effect adjustment, net of tax, to beginning retained earnings as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Retained Earnings Reduction (in thousands)</th>
<th>Tax Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$2,181</td>
<td>$1,175</td>
</tr>
<tr>
<td>CSPCo</td>
<td>1,095</td>
<td>589</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>1,398</td>
<td>753</td>
</tr>
<tr>
<td>OPCo</td>
<td>1,864</td>
<td>1,004</td>
</tr>
<tr>
<td>PSO</td>
<td>1,107</td>
<td>596</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,156</td>
<td>622</td>
</tr>
</tbody>
</table>

In June 2007, the FASB addressed the recognition of income tax benefits of dividends on employee share-based compensation. Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

The Registrant Subsidiaries adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

In September 2008, the FASB issued FSP SFAS 133-1 and FIN 45-4 amending SFAS 133 and FIN 45 “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.” Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

The Registrant Subsidiaries adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements and footnote disclosures.
In December 2008, the FASB issued FSP SFAS 140-4 and FIN 46R-8 amending SFAS 140 “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities” and FIN 46R “Consolidation of Variable Interest Entities.” Under the requirements, the transferor of financial assets in the securitization or asset-backed financing arrangement must disclose the following:

(a) Nature of any restrictions on assets reported by an entity in its balance sheet that relate to a transferred financial asset, including the carrying amounts of such assets.
(b) Method of reporting servicing assets and servicing liabilities.
(c) If reported as sales and the transferor has continuing involvement with the transferred financial assets and the transfers are accounted for as secured borrowings, how the transfer of financial assets affects the transferors’ balance sheet, net income and cash flows.

The FIN 46R amendments contain disclosure requirements for a public enterprise that (a) is the primary beneficiary of a variable interest entity (VIE), (b) holds a significant variable interest in a VIE but is not the primary beneficiary or (c) is a sponsor that holds a variable interest in a VIE. The principle objectives of the disclosures required by this standard are to provide financial statement users an understanding of:

(a) Significant judgments and assumptions made to determine whether to consolidate a variable interest entity and/or disclose information about involvement with a variable interest entity.
(b) Nature of the restrictions on a consolidated variable interest entity’s assets reported in the balance sheet, including the carrying amounts of such assets.
(c) Nature of, and changes in, risks associated with a company’s involvement with a variable interest entity.
(d) A variable interest entity’s effect on the balance sheet, net income and cash flows.
(e) The nature, purpose, size and activities of any variable interest equity, including how it is financed.

The Registrant Subsidiaries adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements but increased the footnote disclosures for variable interest entities. See “Variable Interest Entities” section of Note 15.

**FSP FIN 39-1 “Amendment of FASB Interpretation No. 39” (FSP FIN 39-1)**

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 39 “Offsetting of Amounts Related to Certain Contracts” by replacing the interpretation’s definition of contracts with the definition of derivative instruments per SFAS 133. The amendment requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

The Registrant Subsidiaries adopted the standard effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, the Registrant Subsidiaries reclassified the following amounts on their December 31, 2007 balance sheets as shown:

<table>
<thead>
<tr>
<th>December 2007 10-K Balance Sheet Line Description</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>$ (1,752)</td>
<td>$ (1,006)</td>
<td>$ (969)</td>
<td>$ (1,254)</td>
<td>$ (30)</td>
<td>$ (43)</td>
</tr>
<tr>
<td>Margin Deposits</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Prepayments and Other</td>
<td>(3,306)</td>
<td>(1,917)</td>
<td>(1,841)</td>
<td>(2,232)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Long-term Risk Management Assets</td>
<td>(2,588)</td>
<td>(1,500)</td>
<td>(1,441)</td>
<td>(1,748)</td>
<td>(18)</td>
<td>(22)</td>
</tr>
<tr>
<td>Current Liabilities:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>(3,247)</td>
<td>(1,881)</td>
<td>(1,807)</td>
<td>(2,192)</td>
<td>(33)</td>
<td>(39)</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>(4,340)</td>
<td>(2,507)</td>
<td>(2,410)</td>
<td>(3,002)</td>
<td>(48)</td>
<td>(64)</td>
</tr>
<tr>
<td>Long-term Risk Management Liabilities</td>
<td>(59)</td>
<td>(35)</td>
<td>(34)</td>
<td>(40)</td>
<td>(106)</td>
<td>(126)</td>
</tr>
</tbody>
</table>
For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2008 balance sheets, the Registrant Subsidiaries netted collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>December 31, 2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cash Collateral</td>
</tr>
<tr>
<td></td>
<td>Received</td>
</tr>
<tr>
<td></td>
<td>Netted Against</td>
</tr>
<tr>
<td></td>
<td>Risk Management</td>
</tr>
<tr>
<td></td>
<td>Assets</td>
</tr>
<tr>
<td>APCo</td>
<td>$ 2,189</td>
</tr>
<tr>
<td>CSPCo</td>
<td>1,229</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>1,189</td>
</tr>
<tr>
<td>OPCo</td>
<td>1,522</td>
</tr>
<tr>
<td>PSO</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>-</td>
</tr>
</tbody>
</table>

**Pronouncements Adopted During The First Quarter of 2009**

The following standards are effective during the first quarter of 2009. Consequently, their impact will be reflected in the first quarter of 2009 financial statements when filed. The following paragraphs discuss their expected impact on future financial statement and footnote disclosures.

**SFAS 141 (revised 2007) “Business Combinations” (SFAS 141R)**

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. The Registrant Subsidiaries do not have any such tax positions that result in adjustments.

The Registrant Subsidiaries adopted SFAS 141R effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. The Registrant Subsidiaries will apply it to any future business combinations.

**SFAS 160 “Noncontrolling Interest in Consolidated Financial Statements” (SFAS 160)**

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

The Registrant Subsidiaries adopted SFAS 160 effective January 1, 2009. The adoption of this standard had an immaterial impact and will be applied retrospectively to prior period financial statements in future filings so the presentation of noncontrolling interest is comparable.
**SFAS 161 “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161)**

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation.

The Registrant Subsidiaries adopted SFAS 161 effective January 1, 2009. This standard will increase the disclosure requirements related to derivative instruments and hedging activities in future reports.

**EITF Issue No. 08-5 “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (EITF 08-5)**

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer’s credit standing without the support of the credit enhancement affect the fair value measurement of the issuer’s liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

The Registrant Subsidiaries adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as the Registrant Subsidiaries report fair value of long-term debt annually.

**EITF Issue No. 08-6 “Equity Method Investment Accounting Considerations” (EITF 08-6)**

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

The Registrant Subsidiaries adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

**FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets” (SFAS 142-3)**

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

The Registrant Subsidiaries adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.


**Pronouncements Effective in the Future**

The following standards will be effective in the future and their impacts disclosed at that time.

**FSP SFAS 132R-1 “Employers’ Disclosures about Postretirement Benefit Plan Assets” (FSP SFAS 132R-1)**

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP’s benefit plans. The Registrant Subsidiaries will adopt the standard effective for the 2009 Annual Report.

**Future Accounting Changes**

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of the Registrant Subsidiaries’ operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, insurance, hedge accounting, consolidation policy, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

**EXTRAORDINARY ITEM**

**Virginia Restructuring**

In April 2007, Virginia passed legislation to reestablish regulation for retail generation and supply of electricity. As a result, APCo recorded an extraordinary loss of $118 million ($79 million, net of tax) in 2007 for the reestablishment of regulatory assets and liabilities related to Virginia retail generation and supply operations. In 2000, APCo discontinued SFAS 71 regulatory accounting in the Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation.

3. **GOODWILL AND OTHER INTANGIBLE ASSETS**

**Goodwill**

There is no goodwill carried by any of the Registrant Subsidiaries.

**Other Intangible Assets**

SWEPCo’s acquired intangible asset subject to amortization was $8.8 million and $9.9 million at December 31, 2008 and 2007, respectively, net of accumulated amortization and is included in Deferred Charges and Other on SWEPCo’s Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization are:

<table>
<thead>
<tr>
<th>Amortization Life (in years)</th>
<th>Gross Carrying Amount (in millions)</th>
<th>Accumulated Amortization (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced Royalties</td>
<td>15</td>
<td>$29.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$20.6</td>
</tr>
</tbody>
</table>

December 31, 2008

December 31, 2007

Amortization of the intangible asset was $1 million, $3 million and $3 million for 2008, 2007 and 2006, respectively. SWEPCo’s estimated total amortization is $1.1 million per year for 2009 through 2016, when the asset will be fully amortized with no residual value.
The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. In December 2008, SWEPCo received an order from the LPSC that extended the useful life of the mine for an additional five years, beginning January 1, 2008, which is factored in the estimates noted above.

The Registrant Subsidiaries have no intangible assets that are not subject to amortization.

4. RATE MATTERS

The Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on net income and cash flows.

For discussion of the FERC’s November 2008 order on AEP’s allocation of off-system sales, see “Allocation of Off-system Sales Margins” section within “FERC Rate Matters”.

Ohio Rate Matters

Ohio Electric Security Plan Filings – Affecting CSPCo and OPCo

In April 2008, the Ohio legislature passed Senate Bill 221, which amended the restructuring law effective July 31, 2008 and required electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities could include a fuel cost recovery mechanism (FCR) in their ESP filing. Electric utilities also had an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, would have transitioned CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve and/or modify each utility’s ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than an MRO. Both alternatives involve a “significantly excessive earnings” test (SEET) based on what public companies, including other utilities with similar risk profiles, earn on equity.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo’s and OPCo’s ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a FCR that primarily includes fuel costs, purchased power costs, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The FCR is proposed to be phased into customer bills over the three-year period from 2009 through 2011 and recovered with a weighted average cost of capital carrying cost deferral over seven years from 2012 through 2018. If the ESPs are approved as filed, effective with the implementation of the ESPs, CSPCo and OPCo will defer fuel cost over/under-recoveries and related carrying costs, including amounts unrecovered through the phase in period, for future recovery.

In addition to the FCR, the requested ESP increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include recovery for programs for smart metering initiatives, economic development, mandated energy efficiency, renewable resources and peak demand reduction programs.

Within the ESP requests, CSPCo and OPCo would also recover existing regulatory assets of $47 million and $39 million, respectively, for customer choice implementation and line extension carrying costs incurred through December 2008. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $31 million and $23 million, respectively, through December 2008. The PUCO had previously issued orders allowing deferral of these costs. Such costs would be recovered over an 8-year period beginning January 2011. If the PUCO does not approve recovery of these regulatory assets in this or some future proceeding, it would have an adverse effect on future net income and cash flows.

Hearings were held in November and December 2008. Many intervenors filed opposing testimony. CSPCo and OPCo requested retroactive application of the new rates, including the FCR, back to the start of the January 2009 billing cycle upon approval of the ESPs. The RSP rates were effective for the years ended December 31, 2006, 2007
and 2008 under which CSPCo and OPCo had three annual generation rate increases of 3% and 7%, respectively. The RSP also allowed additional annual generation rate increases of up to an average of 4% per year to recover new governmentally-mandated costs. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. A motion to dismiss the application has been filed by Ohio Partners for Affordable Energy, while the Ohio Consumers’ Counsel has filed comments opposing the application. The PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO issues a ruling on the ESPs or the end of the March 2009 billing cycle, whichever comes first. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs. CSPCo and OPCo anticipate a final order from the PUCO during the first quarter of 2009.

**2008 Generation Rider and Transmission Rider Rate Settlement – Affecting CSPCo and OPCo**

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider (TCRR) provisions of the RSP. The increase was due to additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of increased PJM costs associated with transmission line losses of $39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets during the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings previously expensed from June 2007 to December 2007 for transmission line losses. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR recoveries are under/over actual net costs, CSPCo and OPCo will defer the difference as a regulatory asset or regulatory liability and adjust future customer billings to reflect actual costs, including carrying costs on the deferral. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008. The TCRR continues in CSPCo’s and OPCo’s proposed ESPs to provide for the recovery of PJM related costs.

**2009 Generation Rider and Transmission Rider – Affecting CSPCo and OPCo**

In October 2008, CSPCo and OPCo filed an application to update the TCRR. The application requested an average decrease of 3% for CSPCo and an average increase of 7% for OPCo, including under recoveries from the prior year and related carrying charges. Based on the requests, CSPCo annual revenues would decrease approximately $5 million and OPCo annual revenues would increase approximately $13 million.

In December 2008, the PUCO issued a final order approving the application with certain modifications. First, the rate to calculate carrying costs will change from using a current weighted average cost of capital rate (WACC), which includes a return on equity and a gross up for income taxes, to a long-term debt rate. CSPCo’s and OPCo’s approved long-term debt rates were 5.73% and 5.71%, respectively. In addition, the TCRR application eliminated the fuel-related credit which had been applied against the PJM transmission marginal line loss since CSPCo’s and OPCo’s proposed fuel adjustment clause in the filing of the ESP includes this credit. The new TCRR became effective with the January 2009 billing cycle.

**Ohio IGCC Plant – Affecting CSPCo and OPCo**

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the generation rates which may be a market-based standard service offer price for generation and the expected higher cost of operating and maintaining the plant, including a return on and return of the projected cost to construct the plant.

In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected $12 million in pre-construction costs and incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million.
The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In 2006, intervenors filed four separate appeals of the PUCO’s order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO’s order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved orders of the PUCO. In September 2008, the Ohio Consumers’ Counsel filed a motion with the PUCO requesting all Phase 1 costs be refunded to Ohio ratepayers with interest because the Ohio Supreme Court invalidated the underlying foundation for the Phase 1 recovery. In October 2008, CSPCo and OPCo filed a motion with the PUCO that argued the Ohio Consumers’ Counsel’s motion was without legal merit and contrary to past precedent.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that CSPCo and OPCo have not commenced construction of the IGCC plant and believe there exist real statutory barriers to the construction of any new base load generation in Ohio, including IGCC plants. The statement also indicated that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in the commencement of construction on a continuous course by that time.

As of December 2007 the estimated cost to build the IGCC plant was $2.7 billion which has continued to increase significantly. Management continues to pursue the ultimate construction of the IGCC plant. However, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists.

If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

**Ormet – Affecting CSPCo and OPCo**

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, in accordance with a settlement agreement approved by the PUCO. The settlement agreement allows for the recovery in 2007 and 2008 of the difference between the $43 per MWH Ormet pays for power and a PUCO approved market price, if higher. The PUCO approved a $47.69 per MWH market price for 2007 and the difference was recovered through the amortization of an existing $57 million ($15 million for CSPCo and $42 million for OPCo) regulatory liability related to excess deferred state taxes resulting from the phase-out of an Ohio franchise tax recorded in 2005. During 2007, CSPCo and OPCo each amortized $7 million of this regulatory liability to increase income. During 2008, CSPCo and OPCo each amortized $21.5 million of this regulatory liability to income based on PUCO approved market prices. The settlement agreement required CSPCo and OPCo to exhaust the $57 million regulatory liability. Therefore, CSPCo reimbursed OPCo for $13.5 million of OPCo’s unamortized regulatory liability. The previously approved 2007 price of $47.69 per MWH was used through November 2008 when the PUCO approved a 2008 price of $53.03 per MWH. The additional amortization recorded in December 2008 of $11 million each for CSPCo and OPCo related to the increase in the 2008 PUCO approved market price for the period January 2008 through November 2008. As of December 31, 2008, the regulatory liability was fully amortized.

In December 2008, CSPCo, OPCo and Ormet filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The arrangement would remain in effect and expire upon the effective date of CSPCo’s and OPCo’s new ESP rates and the effective date of a new arrangement between Ormet and CSPCo/OPCo approved by the PUCO. Under the interim arrangement, Ormet would pay the applicable generation tariff rates and riders. CSPCo and OPCo sought to defer as a regulatory asset beginning in 2009 the difference between the PUCO approved 2008 market price and the applicable generation tariff rates and riders. CSPCo and OPCo propose to recover the deferral through the fuel adjustment clause mechanism they
proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement. Although the PUCO did not address recovery in this order, it is expected to be resolved in the pending ESP proceedings. In February 2009, an intervenor filed an application for rehearing of the PUCO’s interim arrangement approval. In February 2009, Ormet filed an application with the PUCO for approval of a proposed power contract for 2009 through 2018. Ormet proposed that it pay varying amounts based on certain conditions, including the price of aluminum. The difference between the amounts paid by Ormet and the otherwise applicable PUCO tariff rate would be either collected from or refunded to CSPCo’s and OPCo’s retail customers.

Hurricane Ike – Affecting CSPCo and OPCo

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. Under the RSP, CSPCo and OPCo could seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively. In December 2008, CSPCo and OPCo filed with the PUCO a request to establish the regulatory assets, plus carrying costs using CSPCo’s and OPCo’s weighted average cost of capital carrying charge rates. In December 2008, the PUCO subsequently approved the establishment of the regulatory assets but authorized CSPCo and OPCo to record a long-term debt only carrying cost on the regulatory asset. In its order approving the deferrals, the PUCO stated that recovery would be determined in CSPCo’s and OPCo’s future filings.

In December 2008, the Consumers for Reliable Electricity in Ohio filed a request with the PUCO asking for an investigation into the service reliability of Ohio’s investor-owned electric utilities, including CSPCo and OPCo. The investigation request includes the widespread outages caused by the September 2008 wind storm. CSPCo and OPCo filed a response asking the PUCO to deny the request.

As a result of the past favorable treatment of storm restoration costs and the RSP provisions, which were in effect when the storm occurred and the filings made, management believes the recovery of the regulatory assets is probable. However, if these regulatory assets are not recovered, it would have an adverse effect on future net income and cash flows.

Virginia Rate Matters

Virginia Base Rate Filing – Affecting APCo

In May 2008, APCo filed an application with the Virginia SCC to increase its base rates by $208 million on an annual basis. The proposed revenue requirement reflected a return on equity of 11.75%. As permitted under Virginia law, APCo implemented these new base rates, subject to refund, effective October 28, 2008.

In October 2008, APCo submitted a $168 million settlement agreement to the Virginia SCC which was accepted by most parties. The $168 million settlement agreement revenue requirement was determined using a 10.2% return on equity and reflected the Virginia SCC staff’s recommended increase as adjusted.

In November 2008, the Virginia SCC issued a final order approving the settlement agreement which increased APCo’s annual base revenues by $168 million. The new authorized rates were implemented in December 2008, retroactive to October 28, 2008. APCo made customer refunds with interest in January 2009 for the difference between the interim rates and the approved rates.

Virginia E&R Costs Recovery Filing – Affecting APCo

In May 2008, APCo filed a request with the Virginia SCC to recover $66 million of its incremental E&R costs incurred for the period of October 2006 to December 2007. In September 2008, a settlement was reached and a stipulation agreement (stipulation) to recover $61 million of costs was submitted to the hearing examiner. The stipulation included recovery of $4.5 million representing one-half of a $9 million Virginia jurisdictional portion of NSR settlement expenses recorded in 2007. In accordance with the stipulation, APCo will request the remaining one-half of the $9 million of NSR settlement expenses in APCo’s 2009 E&R filing.
In September 2008, the hearing examiner recommended that the Virginia SCC accept the stipulation. As a result, in September 2008, APCo deferred as a regulatory asset $9 million of NSR settlement expenses it had expensed in 2007 on the basis that those expenses had become probable of future recovery. In October 2008, the Virginia SCC approved the stipulation which will have a favorable effect on 2009 cash flows of $61 million and on net income for the previously unrecognized equity carrying costs of approximately $11 million.

As of December 31, 2008, APCo has $123 million of deferred Virginia incremental E&R costs (excluding $25 million of unrecognized equity carrying costs). The $123 million consists of $6 million of over recovery of costs collected from the 2008 surcharge, $50 million approved by the Virginia SCC related to APCo’s May 2008 E&R filing to be recovered in 2009, and $79 million, representing costs deferred in 2008, to be included in the 2009 E&R filing, to be collected in 2010.

If the Virginia SCC were to disallow a material portion of APCo’s 2008 deferral of incremental E&R costs including the remaining $4.5 million of the NSR settlement expenses, it would have an adverse effect on future net income and cash flows.

**Virginia Fuel Clause Filing – Affecting APCo**

In July 2008, APCo initiated a fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily related to increases in coal costs. In October 2008, the Virginia SCC ordered an annualized increase of $117 million based on differences in estimated future costs and inclusive of PJM transmission marginal line losses, subject to subsequent true-up to actual.

**APCo’s Filings for an IGCC Plant – Affecting APCo**

In January 2006, APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC plant adjacent to APCo’s existing Mountaineer Generating Station in Mason County, West Virginia.

In June 2007, APCo sought pre-approval with the WVPSC for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing finance costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo’s requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action.

Through December 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to the West Virginia jurisdiction, approximately $2 million applicable to the FERC jurisdiction and approximately $9 million allocated to the Virginia jurisdiction.

In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expense being incurred and certification of the IGCC plant prior to July 2010.
Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

**Mountaineer Carbon Capture Project – Affecting APCo**

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO₂ capture demonstration facility. APCo and Alstom will each own part of the CO₂ capture facility. APCo will also construct and own the necessary facilities to store the CO₂. RWE AG, a German electric power and natural gas public utility, is participating in the evaluation of the commercial and technical feasibility of taking captured CO₂ from the flue gas stream and storing it in deep geologic formations. APCo’s estimated cost for its share of the facilities is $76 million. Through December 31, 2008, APCo incurred $29 million in capitalized project costs which are included in Regulatory Assets. APCo is earning a return on the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. See the “Virginia Base Rate Filing” section above. APCo plans to seek recovery for the CO₂ capture and storage project costs in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. If a significant portion of the deferred project costs are excluded from base rates and ultimately disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.

**West Virginia Rate Matters**

**APCo’s 2008 Expanded Net Energy Cost (ENEC) Filing – Affecting APCo**

In February 2008, APCo filed with the WVPSC for an increase of approximately $140 million including a $122 million increase in the ENEC, a $15 million increase in construction cost surcharges and $3 million of reliability expenditures, to become effective July 2008. In June 2008, the WVPSC issued an order approving a joint stipulation and settlement agreement granting rate increases, effective July 2008, of approximately $95 million based on differences in estimated future costs, including an $79 million increase in the ENEC, a $13 million increase in construction cost surcharges and $3 million of reliability expenditures. The ENEC is an expanded form of a fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits, PJM costs associated with transmission line losses due to the implementation by PJM transmission marginal line loss pricing and other energy/transmission items.

The ENEC and reliability surcharges are subject to a true-up to actual costs. Therefore, there should be no earnings effect if actual costs exceed the recoveries due to the deferral of any under-recovery of costs. The construction cost is not subject to a true-up to actual costs and could impact future net income and cash flows if actual costs exceed the amounts approved for recovery.

**APCo’s Filings for an IGCC Plant – Affecting APCo**

See “APCo’s Filings for an IGCC Plant” section within “Virginia Rate Matters” for disclosure.

**Mountaineer Carbon Capture Project – Affecting APCo**

See “Mountaineer Carbon Capture Project” section within “Virginia Rate Matters” for disclosure.

**Indiana Rate Matters**

**Indiana Base Rate Filing – Affecting I&M**

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The filing also requested trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of PJM transmission marginal line loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers
would initially increase annual revenues by an additional $45 million. I&M proposes to share with customers, through a proposed tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement included a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue. The agreement also establishes an off-system sales sharing mechanism and trackers for PJM, net emission allowance, and DSM costs, among other provisions which include continued funding for the eventual decommissioning of the Cook Nuclear Plant. I&M anticipates a final order from the IURC during the first quarter of 2009.

Rockport and Tanners Creek – Affecting I&M

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NOx and mercury from existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport plant. I&M is requesting to depreciate the ACI systems over a period of 10 years and the SNCR systems over the remaining useful life of the Tanners Creek generating units. I&M requested the IURC to approve a rate adjustment mechanism of unrecovered carrying costs during construction and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the projects are placed in service. I&M also requested the IURC to authorize deferral of costs and carrying costs until such costs are recognized in the rate adjustment mechanism. The IURC has not issued a procedural schedule at this time for this petition. Management is unable to predict the outcome of this petition.

Indiana Fuel Clause Filing – Affecting I&M

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of the extended outage of the Cook Unit 1 due to damage to the main turbine and generator and increased coal prices, and a projection for the future period of fuel costs including Cook Unit 1 replacement power fuel clause costs. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Unit 1 accidental outage policy. See “Cook Plant Unit 1 Fire and Shutdown” section within the “Commitment, Guarantees and Contingencies” footnote for further details. I&M reached an agreement in February 2009 with intervenors to collect the under-recovery over twelve months instead of over six months as proposed. Under the agreement, the fuel factor will go into effect subject to refund and a subdocket will be established to consider issues relating to the Cook Unit 1 outage and I&M’s fuel procurement practices. A decision from the IURC is still pending.

Michigan Rate Matters

Michigan Restructuring – Affecting I&M

Although customer choice commenced for I&M’s Michigan customers on January 1, 2002, I&M’s rates for generation in Michigan continued to be cost-based regulated because none of I&M's customers elected to change suppliers and no alternative electric suppliers were registered to compete in I&M's Michigan service territory. In October 2008, the Governor of Michigan signed legislation to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year and to require the remaining 90% of annual retail load to be phased into cost-based rates. The new legislation also requires utilities to meet certain energy efficiency and renewable portfolio standards and permits cost recovery of meeting those standards. Management continues to conclude that I&M's rates for generation in Michigan are cost-based regulated and that I&M can practice regulatory accounting.
**Oklahoma Rate Matters**

*PSO Fuel and Purchased Power – Affecting PSO*

**2006 and Prior Fuel and Purchased Power**

Proceedings addressing PSO’s historic fuel costs through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement. For further discussion and estimated effect on net income see “Allocation of Off-system Sales Margins” section within “FERC Rate Matters”.

In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that allowed PSO to retain the $42 million from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending.

**2007 Fuel and Purchased Power**

In September 2008, the OCC initiated a review of PSO’s generation, purchased power and fuel procurement processes and costs for 2007. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

*Red Rock Generating Facility – Affecting PSO*

In July 2006, PSO announced an agreement with Oklahoma Gas and Electric Company (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit. PSO would have owned 50% of the new unit. OG&E and PSO requested pre-approval to construct the coal-fired Red Rock Generating Facility (Red Rock) and to implement a recovery rider.

In October 2007, the OCC issued a final order approving PSO’s need for 450 MWs of additional capacity by the year 2012, but rejected the ALJ’s recommendation and denied PSO’s and OG&E’s applications for construction pre-approval. The OCC stated that PSO failed to fully study other alternatives to a coal-fired plant. Since PSO and OG&E could not obtain pre-approval to build Red Rock, PSO and OG&E cancelled the third party construction contract and their joint venture development contract.

In December 2007, PSO filed an application at the OCC requesting recovery of $21 million in pre-construction costs and contract cancellation fees associated with Red Rock. In March 2008, PSO and all other parties in this docket signed a settlement agreement that provided for recovery of $11 million of Red Rock pre-construction costs and carrying costs at PSO’s AFUDC rate beginning in March 2008 and continuing until the $11 million is included in base rates in PSO’s next base rate case. PSO will recover the costs over the expected life of the peaking facilities at the Southwestern Station, and include the costs in rate base in its next base rate filing. The OCC approved the settlement in May 2008. As a result of the settlement, PSO wrote off $10 million of its deferred pre-construction costs/cancellation fees in the first quarter of 2008. The remaining balance of $11 million was recorded as a regulatory asset. In July 2008, PSO filed a base rate case which included $11 million of deferred Red Rock costs plus carrying charges at PSO’s AFUDC rate beginning in March 2008. In January 2009, the OCC approved the base rate case. See “2008 Oklahoma Base Rate Filing” section below.

*Oklahoma 2007 Ice Storms – Affecting PSO*

In January and December 2007, PSO incurred maintenance expenses for two large ice storms. Prior to December 2007, PSO filed with the OCC requesting recovery of the maintenance expenses related to the January 2007 service restoration efforts. PSO proposed in its application to establish a regulatory asset to defer the previously expensed ice storm restoration costs and to offset the regulatory asset with gains from the sale of excess SO\textsubscript{2} emission allowances.
In February 2008, PSO entered into a settlement agreement for recovery of ice storm restoration costs from both ice storms. In March 2008, the OCC approved the settlement agreement subject to a final audit. Therefore, in March 2008, PSO recorded a regulatory asset for the previously expensed ice storm maintenance costs. In October 2008, PSO received final approval to recover $74 million of ice storm costs. PSO has applied and will continue to apply proceeds from sale of excess SO2 emission allowances to reduce the regulatory asset. The estimated net balance that is not recovered from the sale of emission allowances will be amortized and recovered through a rider over a period of five years which began in November 2008. The rider will ultimately be trued-up to recover the entire $74 million regulatory asset. The regulatory asset earns a return of 10.92% until fully recovered.

**2008 Oklahoma Base Rate Filing – Affecting PSO**

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million (later adjusted to $127 million) on an annual basis. PSO has been recovering costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO’s net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO’s non-fuel base revenues and a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO’s program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. This deferral will be recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009.

In January 2009, PSO and one intervenor filed motions with the OCC to modify its final order. PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment the OCC made on prepaid pension funding contained within the OCC final order. The OCC subsequently declined to consider the motions to modify. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several issues. If the Attorney General and/or the intervenor’s Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

**Louisiana Rate Matters**

**Louisiana Compliance Filing – Affecting SWEPCo**

In connection with SWEPCo’s merger related compliance filings, the LPSC approved a settlement agreement in April 2008 that prospectively resolves all issues regarding claims that SWEPCo had over-earned its allowed return. SWEPCo agreed to a formula rate plan (FRP) with a three-year term. Under the plan, beginning in August 2008, rates shall be established to allow SWEPCo to earn an adjusted return on common equity of 10.565%. The adjustments are standard Louisiana rate filing adjustments.

If in the second and third year of the FRP, the adjusted earned return is within the range of 10.015% to 11.115%, no adjustment to rates is necessary. However, if the adjusted earned return is outside of the above-specified range, an FRP rider will be established to increase or decrease rates prospectively. If the adjusted earned return is less than 10.015%, SWEPCo will prospectively increase rates to collect 60% of the difference between 10.565% and the adjusted earned return. Alternatively, if the adjusted earned return is more than 11.115%, SWEPCo will prospectively decrease rates by 60% of the difference between the adjusted earned return and 10.565%. SWEPCo will not record over/under recovery deferrals for refund or future recovery under this FRP.

The settlement provides for a separate credit rider decreasing Louisiana retail base rates by $5 million prospectively over the entire three-year term of the FRP, which shall not affect the adjusted earned return in the FRP calculation. This separate credit rider will cease effective August 2011.
In addition, the settlement provides for a reduction in generation depreciation rates effective October 2007. SWEPCo deferred as a regulatory liability the effects of the expected depreciation reduction through July 2008. SWEPCo will amortize this regulatory liability over the three-year term of the FRP as a reduction to the cost of service used to determine the adjusted earned return.

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In accordance with the settlement, SWEPCo recorded a $4 million regulatory liability related to the reduction in generation depreciation rates. The amount of the unamortized regulatory liability for the reduction in generation depreciation was $3 million as of December 31, 2008. In August 2008, the LPSC approved the settlement and SWEPCo implemented the FRP rates, subject to refund. No provision for refund has been recorded as SWEPCo believes that the rates as implemented are in compliance with the settlement.

**Stall Unit – Affecting SWEPCo**

In May 2006, SWEPCo announced plans to build a new intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit (the Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $384 million, excluding AFUDC, and is expected to be in-service in mid-2010. The Louisiana Department of Environmental Quality issued an air permit for the Stall unit in March 2008.

In March 2007, the PUCT approved SWEPCo’s request for a certificate for the facility based on a prior cost estimate. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million (excluding transmission). In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC has established a procedural schedule with a public hearing for April 2009.

If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized construction costs including any cancellation fees. As of December 31, 2008, SWEPCo has capitalized construction costs of $252 million (including AFUDC) and has contractual construction commitments of an additional $99 million. As of December 31, 2008, if the plant had been cancelled, cancellation fees of $33 million would have been required in order to terminate the construction commitments. If SWEPCo cancels the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

**Turk Plant – Affecting SWEPCo**

See “Turk Plant” section within “Arkansas Rate Matters” for disclosure.

**Arkansas Rate Matters**

**Turk Plant – Affecting SWEPCo**

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with the Oklahoma Municipal Power Authority (OMPA), the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk Plant. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo’s portion estimated to cost $1.2 billion. If approved on a timely basis, the plant is expected to be in-service in 2012.

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.
In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC, (b) capping CO₂ emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT’s order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT’s grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In November 2008, SWEPCo received the air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant’s permit is heard. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit.

In January 2008 and July 2008, SWEPCO filed Certificate of Environmental Compatibility and Public Need (CECPN) applications with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor’s Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission’s final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission’s report, it could impact SWEPCo’s proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of December 31, 2008, SWEPCo has capitalized approximately $510 million of expenditures (including AFUDC) and has significant contractual construction commitments for an additional $727 million. As of December 31, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

**Arkansas Base Rate Filing – Affecting SWEPCo**

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to concurrently recover financing costs related to the Stall and Turk generation plants that are currently under construction. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

**Stall Unit – Affecting SWEPCo**

See “Stall Unit” section within “Louisiana Rate Matters” for disclosure.
FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC’s direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. APCo’s, CSPCo’s, I&M’s and OPCo’s portions of recognized gross SECA revenues are as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>(in millions)</th>
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<tr>
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<td>I&amp;M</td>
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</tbody>
</table>

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the “lost revenues” reflected in the SECA rates should not have been 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 the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ’s initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ’s initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ’s findings on key issues are largely without merit. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ’s initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. APCo’s, CSPCo’s, I&M’s and OPCo’s portions of the provision are as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>2007 (in millions)</th>
<th>2006 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$ 1.7</td>
<td>$ 12.4</td>
</tr>
<tr>
<td>CSPCo</td>
<td>0.9</td>
<td>6.9</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>1.0</td>
<td>7.3</td>
</tr>
<tr>
<td>OPCo</td>
<td>1.3</td>
<td>9.4</td>
</tr>
</tbody>
</table>
In December 2008, an additional settlement agreement was approved by the FERC resulting in the completion of a $2 million settlement applicable to $17 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $9 million applicable to $92 million of SECA revenues. The balance in the reserve for future settlements as of December 2008 was $35 million. In-process settlements total $1 million applicable to $20 million of SECA revenues. In February 2009, the FERC approved the in-process settlements resulting in the completion of a $1 million settlement application to $20 million of SECA revenues. APCo’s, CSPCo’s, I&M’s and OPCo’s reserve balance at December 31, 2008 was:

<table>
<thead>
<tr>
<th>Company</th>
<th>December 31, 2008 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$ 11.0</td>
</tr>
<tr>
<td>CSPCo</td>
<td>6.1</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>6.5</td>
</tr>
<tr>
<td>OPCo</td>
<td>8.4</td>
</tr>
</tbody>
</table>

If the FERC adopts the ALJ’s decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies’ retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP’s zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies’ future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. The remaining 20% is being incurred by AEP until it can revise its rates in Indiana and Michigan to recover these lost revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of its portion of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP’s complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the
FERC denied AEP’s request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

**PJM Transmission Formula Rate Filing – Affecting APCo, CSPCo, I&M and OPCo**

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in a combined increase in annual revenues for the AEP East companies of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of AEP’s transmission facilities so that retail rates for jurisdictions other than Ohio are not affected. Retail rates for CSPCo and OPCo would be increased through the Transmission Cost Recovery Rider (TCRR) totaling approximately $10 million and $12 million, respectively. The TCRR includes a true-up mechanism so CSPCo’s and OPCo’s net income will not be adversely affected by a FERC ordered transmission rate increase. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. In October 2008, AEP began settlement discussions and filed the required compliance filing. Management is unable to predict the outcome of this filing.

**SPP Transmission Formula Rate Filing – Affecting PSO and SWEPCo**

In June 2007, AEPSC filed revised tariffs to establish an up-to-date revenue requirement for SPP transmission services over the facilities owned by PSO and SWEPCo and to implement a transmission cost of service formula rate. PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. If approved as filed, the revised tariff will increase annual network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP pricing zone of SPP by approximately $10 million. In August 2007, the FERC issued an order conditionally accepting PSO’s and SWEPCo’s proposed formula rate, subject to a compliance filing, suspended the effective date until February 1, 2008 and established a hearing schedule and settlement proceedings. New rates, subject to refund, were implemented in February 2008. Multiple intervenors have protested or requested rehearing of the order. A settlement agreement was reached. However, the final settlement documents have not been filed with FERC pending final approval by settling parties.

**Allocation of Off-system Sales Margins – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo**

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology to be reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during this period. In December 2008, the AEP West companies recorded a provision for refund which had a $97 million unfavorable effect on AEP net income. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction refund to be made through the fuel clause recovery mechanism. PSO will begin refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. TCC and TNC in Texas and SWEPCo in Arkansas and Louisiana will be working with their state commissions to determine the effect the FERC order will have on retail rates. Management believes that the existing provision for refund is adequate to address existing and any future refunds that may result from the FERC order.
The table below lists the respective amounts the AEP East companies and the AEP West companies recorded in December 2008 including the net increase (decrease) to net income for the year ended December 31, 2008:

<table>
<thead>
<tr>
<th>AEP East Companies</th>
<th>Amounts to be (Transferred)/Received Including Interest</th>
<th>Increase/ (Decrease) to Net Income</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$(77)</td>
<td>$(50)</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(48)</td>
<td>(32)</td>
</tr>
<tr>
<td>OPCo</td>
<td>(62)</td>
<td>(40)</td>
</tr>
<tr>
<td>CSPCo</td>
<td>(44)</td>
<td>(28)</td>
</tr>
<tr>
<td>KPCo</td>
<td>(19)</td>
<td>(12)</td>
</tr>
<tr>
<td><strong>Total – AEP East Companies</strong></td>
<td><strong>(250)</strong></td>
<td><strong>(162)</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>AEP West Companies</th>
<th>Amounts to be (Transferred)/Received Including Interest</th>
<th>Increase/ (Decrease) to Net Income</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>$72</td>
<td>$12</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>85</td>
<td>20</td>
</tr>
<tr>
<td>TCC</td>
<td>68</td>
<td>23</td>
</tr>
<tr>
<td>TNC</td>
<td>25</td>
<td>10</td>
</tr>
<tr>
<td><strong>Total – AEP West Companies</strong></td>
<td><strong>250</strong></td>
<td><strong>65</strong></td>
</tr>
</tbody>
</table>

| Total – AEP Consolidated | $ - | $ - | $ (97) |

The table below shows the vintage year of the associated AEP SIA refunds:

<table>
<thead>
<tr>
<th>AEP East Companies</th>
<th>For the Twelve Months Ended December 31,</th>
<th>2006 and Prior</th>
<th>2007</th>
<th>2008</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td>$</td>
<td>(66)</td>
<td>$ (6)</td>
<td>$ (5)</td>
<td>$ (77)</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(41)</td>
<td>(4)</td>
<td>$ (3)</td>
<td></td>
<td>$ (48)</td>
</tr>
<tr>
<td>OPCo</td>
<td>(53)</td>
<td>(5)</td>
<td>$ (4)</td>
<td></td>
<td>$ (62)</td>
</tr>
<tr>
<td>CSPCo</td>
<td>(40)</td>
<td>(3)</td>
<td>$ (1)</td>
<td></td>
<td>$ (44)</td>
</tr>
<tr>
<td>KPCo</td>
<td>(17)</td>
<td>(1)</td>
<td>$ (1)</td>
<td></td>
<td>$ (19)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>AEP West Companies</th>
<th>For the Twelve Months Ended December 31,</th>
<th>2006 and Prior</th>
<th>2007</th>
<th>2008</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>62</td>
<td>6</td>
<td>4</td>
<td>72</td>
<td></td>
</tr>
<tr>
<td>SWEPCo</td>
<td>74</td>
<td>6</td>
<td>5</td>
<td>85</td>
<td></td>
</tr>
<tr>
<td>TCC</td>
<td>59</td>
<td>5</td>
<td>4</td>
<td>68</td>
<td></td>
</tr>
<tr>
<td>TNC</td>
<td>22</td>
<td>2</td>
<td>1</td>
<td>25</td>
<td></td>
</tr>
<tr>
<td><strong>Total – AEP West Companies</strong></td>
<td><strong>217</strong></td>
<td><strong>19</strong></td>
<td><strong>14</strong></td>
<td><strong>250</strong></td>
<td></td>
</tr>
</tbody>
</table>

| Total – AEP Consolidated | $ - | $ - | $ - | $ - |

Management cannot predict the outcome of the requested FERC rehearing proceeding or any future regulatory proceedings but believes the provision regarding future regulatory proceedings is adequate.

**Transmission Equalization Agreement – Affecting APCo, CSPCo, I&M and OPCo**

Certain transmission equipment placed in service in 1998 was inadvertently excluded from the AEP East companies’ TEA calculation prior to January 2009. Management believes that it is not probable that a material retroactive adjustment will result from the omission. If a retroactive adjustment is required for APCo, CSPCo, I&M and OPCo, it could have an adverse effect on future net income, cash flows and financial condition.
5. **EFFECTS OF REGULATION**

Regulatory assets and liabilities are comprised of the following items:

<table>
<thead>
<tr>
<th>Regulatory Assets:</th>
<th>APCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31,</td>
<td>December 31,</td>
</tr>
<tr>
<td></td>
<td>2008 (in thousands)</td>
<td>2007 (in thousands)</td>
</tr>
<tr>
<td><strong>Current Regulatory Asset</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under-recovered Fuel Costs</td>
<td>$ 165,906</td>
<td>$ -</td>
</tr>
<tr>
<td><strong>Noncurrent Regulatory Assets</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SFAS 109 Regulatory Asset, Net (See Note 12)</td>
<td>$ 424,334</td>
<td>$ 400,580</td>
</tr>
<tr>
<td>SFAS 158 Regulatory Asset (See Note 8)</td>
<td>344,624</td>
<td>91,619</td>
</tr>
<tr>
<td>Environmental and Reliability Costs (See Note 4)</td>
<td>123,060</td>
<td>81,488</td>
</tr>
<tr>
<td>Mountaineer Carbon Capture Project (See Note 4)</td>
<td>29,250</td>
<td>-</td>
</tr>
<tr>
<td>SFAS 112 Regulatory Asset</td>
<td>21,473</td>
<td>16,939</td>
</tr>
<tr>
<td>Asset Retirement Obligation</td>
<td>16,630</td>
<td>18,666</td>
</tr>
<tr>
<td>Unamortized Loss on Reacquired Debt</td>
<td>15,367</td>
<td>13,541</td>
</tr>
<tr>
<td>Restructuring Transition Costs – Virginia</td>
<td>8,489</td>
<td>12,734</td>
</tr>
<tr>
<td>Cook Nuclear Plant Refueling Outage Levelization</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>15,834</td>
<td>17,172</td>
</tr>
<tr>
<td><strong>Total Noncurrent Regulatory Assets</strong></td>
<td>$ 999,061</td>
<td>$ 652,739</td>
</tr>
<tr>
<td><strong>Regulatory Liabilities:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Current Regulatory Liabilities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Over-recovered Fuel Costs</td>
<td>-</td>
<td>$ 23,637</td>
</tr>
<tr>
<td><strong>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asset Removal Costs</td>
<td>$ 438,042</td>
<td>$ 417,087</td>
</tr>
<tr>
<td>Unrealized Gain on Forward Commitments</td>
<td>38,345</td>
<td>22,274</td>
</tr>
<tr>
<td>Deferred State Income Tax Coal Credits</td>
<td>25,131</td>
<td>20,746</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>15,075</td>
<td>19,284</td>
</tr>
<tr>
<td>Over-recovered ENEC Costs</td>
<td>3,824</td>
<td>25,110</td>
</tr>
<tr>
<td>Excess ARO for Nuclear Decommissioning (See Note 10)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>1,091</td>
<td>1,055</td>
</tr>
<tr>
<td><strong>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</strong></td>
<td>$ 521,508</td>
<td>$ 505,556</td>
</tr>
</tbody>
</table>

(a) Amount does not earn a return.
(b) Amount earns a return.
(c) A portion of this amount earns a return.
(d) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(e) This is the difference in the cumulative amount of removal costs recovered through rates and the cumulative amount of ARO as measured by applying SFAS 143 “Accounting for Asset Retirement Obligations.” This amount earns a return, accrues monthly and will be paid when the nuclear plant is decommissioned.
(f) Amortized and recovered over the period beginning with the commencement of an outage and ending with the beginning of the next outage.
(g) Recovery/refund period – various periods.
(h) Recovery/refund period – 1 year.
(i) Recovery/refund period – 2 years.
(j) Recovery/refund period – up to 9 years.
(k) Recovery/refund period – up to 12 years.
(l) Recovery/refund period – up to 78 years.
(m) Recovery/refund period – up to 28 years.
(n) Recovery/refund period – up to 24 years.
(o) Recovery method and timing to be determined in future proceedings.
(p) Current Regulatory Liability – Over-recovered Fuel Costs are recorded in Other on APCo’s and I&M’s Consolidated Balance Sheets.
### Regulatory Assets:

<table>
<thead>
<tr>
<th>Noncurrent Regulatory Assets</th>
<th>CSPCo</th>
<th>OPCo</th>
<th>Notes</th>
<th>CSPCo</th>
<th>OPCo</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31, 2008</td>
<td>Notes</td>
<td>December 31, 2007</td>
<td>Notes</td>
<td>December 31, 2008</td>
<td>Notes</td>
</tr>
<tr>
<td>SFAS 158 Regulatory Asset (See Note 8)</td>
<td>$187,821</td>
<td>$71,180</td>
<td>(a) (e)</td>
<td>$203,326</td>
<td>$68,062</td>
<td>(a) (e)</td>
</tr>
<tr>
<td>Customer Choice Deferrals (See Note 4)</td>
<td>27,377</td>
<td>26,608</td>
<td>(b) (j)</td>
<td>27,707</td>
<td>26,867</td>
<td>(b) (j)</td>
</tr>
<tr>
<td>Line Extension Carrying Costs</td>
<td>19,933</td>
<td>15,657</td>
<td>(b) (j)</td>
<td>11,341</td>
<td>7,071</td>
<td>(b) (j)</td>
</tr>
<tr>
<td>Hurricane Ike (See Note 4)</td>
<td>17,300</td>
<td>-</td>
<td>(b) (j)</td>
<td>10,100</td>
<td>-</td>
<td>(b) (j)</td>
</tr>
<tr>
<td>SFAS 109 Regulatory Asset, Net (See Note 12)</td>
<td>15,070</td>
<td>15,135</td>
<td>(a) (e)</td>
<td>170,357</td>
<td>166,011</td>
<td>(a) (e)</td>
</tr>
<tr>
<td>Unamortized Loss on Reacquired Debt</td>
<td>10,100</td>
<td>10,858</td>
<td>(b) (h)</td>
<td>8,497</td>
<td>10,116</td>
<td>(b) (i)</td>
</tr>
<tr>
<td>Restructuring Transition Costs – Ohio</td>
<td>-</td>
<td>49,356</td>
<td>(a) (f)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>20,756</td>
<td>47,089</td>
<td>(c) (e)</td>
<td>17,888</td>
<td>44,978</td>
<td>(c) (e)</td>
</tr>
<tr>
<td><strong>Total Noncurrent Regulatory Assets</strong></td>
<td><strong>$298,357</strong></td>
<td><strong>$235,883</strong></td>
<td>(a) (e)</td>
<td><strong>$449,216</strong></td>
<td><strong>$323,105</strong></td>
<td>(a) (e)</td>
</tr>
</tbody>
</table>

### Regulatory Liabilities:

<table>
<thead>
<tr>
<th>Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</th>
<th>CSPCo</th>
<th>OPCo</th>
<th>Notes</th>
<th>CSPCo</th>
<th>OPCo</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31, 2008</td>
<td>Notes</td>
<td>December 31, 2007</td>
<td>Notes</td>
<td>December 31, 2008</td>
<td>Notes</td>
</tr>
<tr>
<td>Asset Removal Costs</td>
<td>$132,493</td>
<td>$130,014</td>
<td>(d)</td>
<td>$117,410</td>
<td>$116,685</td>
<td>(d)</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>18,813</td>
<td>20,767</td>
<td>(a) (h)</td>
<td>2,917</td>
<td>3,859</td>
<td>(c) (g)</td>
</tr>
<tr>
<td>Unrealized Gain on Forward Commitments</td>
<td>3,487</td>
<td>-</td>
<td>(a) (f)</td>
<td>4,319</td>
<td>-</td>
<td>(a) (f)</td>
</tr>
<tr>
<td>Excess Deferred State Income Taxes Due to the Phase Out of the Ohio Franchise Tax (See Note 4 - Ormet)</td>
<td>-</td>
<td>8,150</td>
<td>(a) (f)</td>
<td>-</td>
<td>34,910</td>
<td>(a) (f)</td>
</tr>
<tr>
<td>Other</td>
<td>6,309</td>
<td>6,704</td>
<td>(c) (e)</td>
<td>3,142</td>
<td>5,267</td>
<td>(a) (e)</td>
</tr>
<tr>
<td><strong>Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits</strong></td>
<td><strong>$161,102</strong></td>
<td><strong>$165,635</strong></td>
<td>(a) (e)</td>
<td><strong>$127,788</strong></td>
<td><strong>$160,721</strong></td>
<td>(a) (e)</td>
</tr>
</tbody>
</table>

(a) Amount does not earn a return.
(b) Amount earns a return.
(c) A portion of this amount earns a return.
(d) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(e) Recovery/refund period – various periods.
(f) Recovery/refund period – 1 year.
(g) Recovery/refund period – up to 11 years.
(h) Recovery/refund period – up to 16 years.
(i) Recovery/refund period – up to 30 years.
(j) Recovery method and timing to be determined in future proceedings.
### Regulatory Assets:

#### Current Regulatory Asset

<table>
<thead>
<tr>
<th></th>
<th>PSO 2008</th>
<th>PSO 2007</th>
<th>SWEPCo 2008</th>
<th>SWEPCo 2007</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under-recovered Fuel Costs</td>
<td>$146</td>
<td>$ -</td>
<td>$75,006</td>
<td>$5,859</td>
<td>(b) (f) (n)</td>
</tr>
</tbody>
</table>

#### Noncurrent Regulatory Assets

<table>
<thead>
<tr>
<th>Administrative and Regulatory Programs</th>
<th>PSO 2008</th>
<th>PSO 2007</th>
<th>SWEPCo 2008</th>
<th>SWEPCo 2007</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>SFAS 158 Regulatory Asset (See Note 8)</td>
<td>$176,071</td>
<td>$63,077</td>
<td>$142,554</td>
<td>$52,266</td>
<td>(a) (e)</td>
</tr>
<tr>
<td>Oklahoma 2007 Ice Storms (See Note 4)</td>
<td>61,994</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(b) (l)</td>
</tr>
<tr>
<td>Lawton Settlement</td>
<td>21,101</td>
<td>32,303</td>
<td>-</td>
<td>-</td>
<td>(b) (k)</td>
</tr>
<tr>
<td>Vegetation Management</td>
<td>17,900</td>
<td>15,464</td>
<td>-</td>
<td>-</td>
<td>(a) (e)</td>
</tr>
<tr>
<td>Red Rock Generating Facility (See Note 4)</td>
<td>10,508</td>
<td>20,614</td>
<td>-</td>
<td>-</td>
<td>(b) (m)</td>
</tr>
<tr>
<td>Unamortized Loss on Reacquired Debt</td>
<td>6,521</td>
<td>8,632</td>
<td>15,243</td>
<td>15,569</td>
<td>(b) (g)</td>
</tr>
<tr>
<td>Unrealized Loss on Forward Commitments</td>
<td>-</td>
<td>18,641</td>
<td>-</td>
<td>14,465</td>
<td>(a) (e)</td>
</tr>
<tr>
<td>SFAS 109 Regulatory Asset, Net (See Note 12)</td>
<td>N/A</td>
<td>N/A</td>
<td>40,479</td>
<td>37,614</td>
<td>(b) (e)</td>
</tr>
<tr>
<td>Other</td>
<td>10,642</td>
<td>-</td>
<td>11,898</td>
<td>13,703</td>
<td>(c) (e)</td>
</tr>
</tbody>
</table>

**Total Noncurrent Regulatory Assets**

<table>
<thead>
<tr>
<th></th>
<th>PSO</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>SWEPCo</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$304,737</td>
<td>$158,731</td>
<td>$210,174</td>
<td>$133,617</td>
<td></td>
</tr>
</tbody>
</table>

#### Regulatory Liabilities:

#### Current Regulatory Liability

<table>
<thead>
<tr>
<th></th>
<th>PSO</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>SWEPCo</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Over-recovered Fuel Costs</td>
<td>$58,395</td>
<td>$11,697</td>
<td>$5,162</td>
<td>$22,879</td>
<td>(b) (f)</td>
</tr>
</tbody>
</table>

#### Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits

<table>
<thead>
<tr>
<th></th>
<th>PSO</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>SWEPCo</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Asset Removal Costs</td>
<td>$284,262</td>
<td>$267,504</td>
<td>$303,865</td>
<td>$284,345</td>
<td>(d)</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>27,364</td>
<td>25,535</td>
<td>18,894</td>
<td>22,859</td>
<td>(a) (i)</td>
</tr>
<tr>
<td>SFAS 109 Regulatory Liability, Net (See Note 12)</td>
<td>7,077</td>
<td>8,795</td>
<td>N/A</td>
<td>N/A</td>
<td>(b) (e)</td>
</tr>
<tr>
<td>Unrealized Gain on Forward Commitments</td>
<td>1,598</td>
<td>25,473</td>
<td>1,575</td>
<td>19,565</td>
<td>(a) (e)</td>
</tr>
<tr>
<td>Other</td>
<td>3,449</td>
<td>11,481</td>
<td>11,415</td>
<td>7,245</td>
<td>(c) (e)</td>
</tr>
</tbody>
</table>

**Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits**

<table>
<thead>
<tr>
<th></th>
<th>PSO</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>SWEPCo</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$323,750</td>
<td>$338,788</td>
<td>$335,749</td>
<td>$334,014</td>
<td></td>
</tr>
</tbody>
</table>

(a) Amount does not earn a return.
(b) Amount earns a return.
(c) A portion of this amount earns a return.
(d) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(e) Recovery/refund period – various periods.
(f) Recovery/refund period – 1 year.
(g) Recovery/refund period – up to 11 years.
(h) Recovery/refund period – up to 9 years.
(i) Recovery/refund period – up to 56 years.
(j) Recovery/refund period – up to 35 years.
(k) Recovery/refund period – 2 years.
(l) Recovery/refund period – 5 years.
(m) Recovery/refund period – up to 48 years.
(n) Current Regulatory Asset – Under-recovered Fuel Costs are recorded in Prepayments and Other on PSO’s Balance Sheets.

N/A Not applicable, asset and liability are shown net.
6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements.

**Insurance and Potential Losses – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo**

The Registrant Subsidiaries maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by the Registrant Subsidiaries. Coverage is generally provided by a combination of a South Carolina domiciled insurance company, EIS, together with and/or in addition to various industry mutual and commercial insurance carriers.

See Note 9 for a discussion of I&M’s nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and financial condition.

**COMMITMENTS**

**Construction and Commitments – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo**

The Registrant Subsidiaries have substantial construction commitments to support their operations and environmental investments. In managing the overall construction program and in the normal course of business, the Registrant Subsidiaries contractually commit to third-party construction vendors for certain material purchases and other construction services. The following table shows the budgeted construction expenditures by Registrant Subsidiary for 2009:

<table>
<thead>
<tr>
<th>Company</th>
<th>Budgeted Construction Expenditures (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$367.5</td>
</tr>
<tr>
<td>CSPCo</td>
<td>269.6</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>361.6</td>
</tr>
<tr>
<td>OPCo</td>
<td>439.4</td>
</tr>
<tr>
<td>PSO</td>
<td>187.7</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>457.4</td>
</tr>
</tbody>
</table>

Budgeted construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

The Registrant Subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination. Management does not expect to incur penalty payments under these provisions that would materially affect net income, cash flows or financial condition.
The following table summarizes the Registrant Subsidiaries’ actual contractual commitments at December 31, 2008:

<table>
<thead>
<tr>
<th>Contractual Commitments – APCo</th>
<th>Less Than 1 Year</th>
<th>2-3 Years</th>
<th>4-5 Years</th>
<th>After 5 Years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$990.5</td>
<td>$1,061.1</td>
<td>$474.8</td>
<td>$1,166.1</td>
<td>$3,692.5</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>14.3</td>
<td>32.5</td>
<td>26.9</td>
<td>212.8</td>
<td>286.5</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>85.2</td>
<td>160.9</td>
<td>89.3</td>
<td>-</td>
<td>335.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$1,090.0</td>
<td>$1,254.5</td>
<td>$591.0</td>
<td>$1,378.9</td>
<td>$4,314.4</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Contractual Commitments - CSPCo</th>
<th>Less Than 1 Year</th>
<th>2-3 Years</th>
<th>4-5 Years</th>
<th>After 5 Years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$215.7</td>
<td>$405.0</td>
<td>$279.3</td>
<td>$400.2</td>
<td>$1,300.2</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>1.5</td>
<td>4.7</td>
<td>0.9</td>
<td>-</td>
<td>7.1</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>35.6</td>
<td>43.2</td>
<td>40.8</td>
<td>-</td>
<td>119.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$252.8</td>
<td>$452.9</td>
<td>$321.0</td>
<td>$400.2</td>
<td>$1,426.9</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Contractual Commitments – I&amp;M</th>
<th>Less Than 1 Year</th>
<th>2-3 Years</th>
<th>4-5 Years</th>
<th>After 5 Years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$539.6</td>
<td>$780.3</td>
<td>$178.5</td>
<td>$30.0</td>
<td>$1,528.4</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>1.4</td>
<td>4.5</td>
<td>0.9</td>
<td>-</td>
<td>6.8</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>16.5</td>
<td>27.4</td>
<td>14.4</td>
<td>-</td>
<td>58.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$557.5</td>
<td>$812.2</td>
<td>$193.8</td>
<td>$30.0</td>
<td>$1,593.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Contractual Commitments – OPCo</th>
<th>Less Than 1 Year</th>
<th>2-3 Years</th>
<th>4-5 Years</th>
<th>After 5 Years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$1,253.2</td>
<td>$1,576.7</td>
<td>$1,032.1</td>
<td>$3,157.7</td>
<td>$7,019.7</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>1.9</td>
<td>5.8</td>
<td>1.1</td>
<td>-</td>
<td>8.8</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>19.4</td>
<td>29.1</td>
<td>43.7</td>
<td>-</td>
<td>92.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$1,274.5</td>
<td>$1,611.6</td>
<td>$1,076.9</td>
<td>$3,157.7</td>
<td>$7,120.7</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Contractual Commitments – PSO</th>
<th>Less Than 1 Year</th>
<th>2-3 Years</th>
<th>4-5 Years</th>
<th>After 5 Years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$244.7</td>
<td>$120.4</td>
<td>$42.6</td>
<td>-</td>
<td>$407.7</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>13.1</td>
<td>14.5</td>
<td>-</td>
<td>-</td>
<td>27.6</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>10.6</td>
<td>51.4</td>
<td>73.3</td>
<td>-</td>
<td>135.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$268.4</td>
<td>$186.3</td>
<td>$115.9</td>
<td>-</td>
<td>$570.6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Contractual Commitments – SWEPCo</th>
<th>Less Than 1 Year</th>
<th>2-3 Years</th>
<th>4-5 Years</th>
<th>After 5 Years</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Purchase Contracts (a)</td>
<td>$379.9</td>
<td>$670.4</td>
<td>$523.4</td>
<td>$2,607.7</td>
<td>$4,181.4</td>
</tr>
<tr>
<td>Energy and Capacity Purchase Contracts (b)</td>
<td>18.5</td>
<td>9.4</td>
<td>9.6</td>
<td>54.6</td>
<td>92.1</td>
</tr>
<tr>
<td>Construction Contracts for Capital Assets (c)</td>
<td>313.4</td>
<td>554.8</td>
<td>278.7</td>
<td>-</td>
<td>1,146.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$711.8</td>
<td>$1,234.6</td>
<td>$811.7</td>
<td>$2,662.3</td>
<td>$5,420.4</td>
</tr>
</tbody>
</table>

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel. The longest contract extends to 2020 for APCo, 2021 for CSPCo, 2014 for I&M, 2021 for OPCo, 2013 for PSO and 2035 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release the Registrant Subsidiary from its commitments under certain conditions.

(b) Represents contractual commitments for energy and capacity purchase contracts.

(c) Represents only capital assets that are contractual commitments.
GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits and debt service reserves. These LOCs were issued in the ordinary course of business under the two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $46 million following its bankruptcy.

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of December 31, 2008, $372 million of letters of credit were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

At December 31, 2008, the maximum future payments of the LOCs were as follows:

<table>
<thead>
<tr>
<th>Borrower</th>
<th>Amount (in thousands)</th>
<th>Maturity</th>
<th>Sublimit</th>
</tr>
</thead>
<tbody>
<tr>
<td>I&amp;M</td>
<td>$ 1,113</td>
<td>March 2009</td>
<td>N/A</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>4,000</td>
<td>December 2009</td>
<td>N/A</td>
</tr>
<tr>
<td>APCo</td>
<td>$126,716</td>
<td>June 2009</td>
<td>$300,000</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>77,886</td>
<td>May 2009</td>
<td>230,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>166,899</td>
<td>June 2009</td>
<td>400,000</td>
</tr>
</tbody>
</table>

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of December 31, 2008, SWEPCo has collected approximately $38 million through a rider for final mine closure costs, of which approximately $700 thousand is recorded in Other Current Liabilities and $37.6 million is recorded in Deferred Credits and Other on SWEPCo’s Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to December 31, 2008, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.
**Lease Obligations**

Certain Registrant Subsidiaries lease certain equipment under master lease agreements. See “Master Lease Agreements” and “Railcar Lease” sections of Note 13 for disclosure of lease residual value guarantees.

**CONTINGENCIES**

**Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo**

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

In 2007, the U.S. District Court approved the AEP System’s consent decree with the Federal EPA, the DOJ, the states and the special interest groups. The consent decree resolved all issues related to various parties’ claims in the NSR cases. Under the consent decree, the AEP System paid a $15 million civil penalty in 2008 and provided $36 million for environmental projects coordinated with the federal government and $24 million to the states for environmental mitigation. The Registrant Subsidiaries expensed their share of these amounts in 2007 as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Penalty (in thousands)</th>
<th>Environmental Mitigation Costs (in thousands)</th>
<th>Total Expensed in 2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>4,974</td>
<td>20,659</td>
<td>25,633</td>
</tr>
<tr>
<td>CSPCo</td>
<td>2,883</td>
<td>11,973</td>
<td>14,856</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2,770</td>
<td>11,503</td>
<td>14,273</td>
</tr>
<tr>
<td>OPCo</td>
<td>3,355</td>
<td>13,935</td>
<td>17,290</td>
</tr>
</tbody>
</table>

In October 2008, the court approved a consent decree for a settlement reached with the Sierra Club in a case involving CSPCo’s share of jointly-owned units at the Stuart Station. The Stuart units, operated by DP&L, are equipped with SCR and FGD controls. Under the terms of the settlement, the joint-owners agreed to certain emission targets related to NOx, SO2 and PM. They also agreed to make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program. Another case involving a jointly-owned Beckjord unit had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, CSPCo might have for civil penalties under the pending CAA proceeding for Beckjord. Management is also unable to predict the timing of resolution of these matters. If the joint-owners do not prevail, management believes that APCo, CSPCo, I&M and OPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through future regulated rates or market prices of electricity. If APCo, CSPCo, I&M and OPCo are unable to recover such costs or if material penalties are imposed, it would adversely affect their future net income, cash flows and possibly financial condition.

**Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo**

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in federal district court for the Eastern District of Texas alleging violations of the CAA at SWEPCo’s Welsh Plant. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs’ attorneys’ fees and costs. The consent decree was entered as a final order in June 2008.
In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. A permit alteration was issued in March 2007 that clarified or eliminated certain of the permit conditions. In June 2007, TCEQ denied a motion to overturn the permit alteration. The permit alteration was appealed to the Travis County District Court, but was resolved by entry of the consent decree in the federal citizen suit action, and dismissed with prejudice in July 2008. Notice of an administrative settlement of the TCEQ enforcement action was published in June 2008. The settlement requires SWEPCo to pay an administrative penalty of $49 thousand and to fund a supplemental environmental project in the amount of $49 thousand, and resolves all violations alleged by TCEQ. In October 2008, TCEQ approved the settlement.

In February 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that the permit alteration issued by TCEQ was improper. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit.

Management is unable to predict the timing of any future action by the Federal EPA or the effect of such actions on net income, cash flows or financial condition.

Carbon Dioxide Public Nuisance Claims – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants’ power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO2 and other greenhouse gases under the CAA, which may impact the Second Circuit’s analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court’s decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages’ Claims – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants’ emissions of CO2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The Registrant Subsidiaries currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2008, APCo is named as a Potentially Responsible Party (PRP) for one site and CSPCo, I&M and OPCo are each named a PRP for two sites by the Federal EPA. There are eight additional sites for which APCo, CSPCo, I&M, OPCo, and SWEPCo have received information requests which could lead to PRP designation. I&M and SWEPCo have also been named
potentially liable at two sites each under state law including the I&M site discussed in the next paragraph. In those instances where AEP subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms. I&M recorded approximately $4 million of expense through December 31, 2008. As the remediation work is completed, I&M’s cost may increase. Management cannot predict the amount of additional cost, if any. At present, management’s estimates do not anticipate material cleanup costs for this site.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made regarding potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, management’s estimates do not anticipate material cleanup costs for identified sites.

Clean Air Interstate Rule – Affecting I&M

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR). It requires specific reductions in SO₂ and NOₓ emissions from power plants and assists states developing new SIPs to meet the NAAQS. CAIR reduces regional emissions of SO₂ and NOₓ (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO₂ by 50% by 2010, and by 65% by 2015. NOₓ emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reductions of both SO₂ and NOₓ would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate CAIR and remanded the rule to the Federal EPA. In September 2008, the Federal EPA and other parties filed petitions for rehearing. In December 2008, the D.C. Circuit Court of Appeals granted the Federal EPA’s petition and remanded the rule to the Federal EPA without vacatur, allowing CAIR to remain in effect while a new rulemaking is conducted. I&M purchased $9 million of CAIR allowances that will be used beginning in 2009.

Cook Plant Unit 1 Fire and Shutdown – Affecting I&M

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. Management’s current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

The refueling outage for Cook Plant Unit 2, which continues to operate at full power, will take place as scheduled in the spring of 2009. The refueling outage scheduled for the fall of 2009 for Unit 1 is currently being evaluated. Management anticipates that the loss of capacity from Unit 1 will not affect I&M’s ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.
I&M maintains property insurance through NEIL with a $1 million deductible. As of December 31, 2008, I&M recorded $28 million in Prepayments and Other on its Consolidated Balance Sheet representing recoverable amounts under property insurance proceeds. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy effective December 15, 2008. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

In January 2009, I&M filed its regular semi-annual fuel filing in Indiana which determines the fuel rate for the period April 2009 through September 2009. I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the forecast period. I&M has deferred $9 million of accidental outage insurance proceeds as of December 31, 2008 which is included in Other Current Liabilities on its Consolidated Balance Sheet.

**Coal Transportation Rate Dispute - Affecting PSO**

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF’s underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In February 2007, the U.S. District Court granted BNSF’s Motion to Reconsider. PSO filed a substantive response to BNSF’s motion and BNSF filed a reply. Management continues to defend its position that PSO paid BNSF all amounts owed.

**Rail Transportation Litigation – Affecting PSO**

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied AEP’s motion to dismiss the case. Management intends to vigorously defend against these allegations. Management believes a provision recorded in 2008 should be sufficient.

**FERC Long-term Contracts – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo**

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were “high-priced.” The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court
Court affirmed the Ninth Circuit’s remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. The Registrant Subsidiaries asserted claims against certain companies that sold power to them, which was resold to the Nevada utilities, seeking to recover a portion of any amounts the Registrant Subsidiaries may owe to the Nevada utilities. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.

7. ACQUISITION

2008

None

2007

Darby Electric Generating Station – Affecting CSPCo

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby Plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

2006

None

8. BENEFIT PLANS

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in AEP sponsored qualified pension plans (merged at December 31, 2008) and unfunded nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo adopted SFAS 158 in December 2006 and recognized the obligations associated with defined benefit pension plans and OPEB plans in their balance sheets. APCo, CSPCo, I&M, OPCo, PSO and SWEPCo recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that are not recognized as a component of net periodic benefit cost. APCo, CSPCo, I&M, OPCo, PSO and SWEPCo recognize an asset or liability for a plan’s overfunded status or a liability for a plan’s underfunded status.

<table>
<thead>
<tr>
<th>Company</th>
<th>Total Adjustment (in thousands)</th>
<th>Regulatory Asset (in thousands)</th>
<th>Deferred Income Tax (in thousands)</th>
<th>AOCI Equity Reduction (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$204,456</td>
<td>$124,080</td>
<td>$28,132</td>
<td>$52,244</td>
</tr>
<tr>
<td>CSPCo</td>
<td>133,980</td>
<td>94,924</td>
<td>13,670</td>
<td>25,386</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>111,040</td>
<td>101,673</td>
<td>3,278</td>
<td>6,089</td>
</tr>
<tr>
<td>OPCo</td>
<td>191,229</td>
<td>92,729</td>
<td>34,475</td>
<td>64,025</td>
</tr>
<tr>
<td>PSO</td>
<td>73,203</td>
<td>73,203</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>78,709</td>
<td>59,649</td>
<td>6,671</td>
<td>12,389</td>
</tr>
</tbody>
</table>

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating market conditions, investment returns and discount rates.
The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP’s plans over the two-year period ending at the plan’s measurement date of December 31, 2008, and their funded status as of December 31 for each year:

*Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2008 and 2007*

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Projected Obligation at January 1</td>
<td>$4,109</td>
<td>$4,108</td>
</tr>
<tr>
<td>Service Cost</td>
<td>100</td>
<td>96</td>
</tr>
<tr>
<td>Interest Cost</td>
<td>249</td>
<td>235</td>
</tr>
<tr>
<td>Actuarial Loss (Gain)</td>
<td>139</td>
<td>(64)</td>
</tr>
<tr>
<td>Plan Amendments</td>
<td>-</td>
<td>18</td>
</tr>
<tr>
<td>Benefit Payments</td>
<td>(296)</td>
<td>(284)</td>
</tr>
<tr>
<td>Participant Contributions</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Medicare Subsidy</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Projected Obligation at December 31</td>
<td>$4,301</td>
<td>$4,109</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Fair Value of Plan Assets at January 1</td>
<td>$4,504</td>
<td>$4,346</td>
</tr>
<tr>
<td>Actual Gain (Loss) on Plan Assets</td>
<td>(1,054)</td>
<td>435</td>
</tr>
<tr>
<td>Company Contributions</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Participant Contributions</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Benefit Payments</td>
<td>(296)</td>
<td>(284)</td>
</tr>
<tr>
<td>Fair Value of Plan Assets at December 31</td>
<td>$3,161</td>
<td>$4,504</td>
</tr>
<tr>
<td>Funded (Underfunded) Status at December 31</td>
<td>$(1,140)</td>
<td>$395</td>
</tr>
</tbody>
</table>

AEP has significant investments in several trust funds to provide for future pension and OPEB payments. All of the trust funds’ investments are diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds’ ability to make their required payments.

*Amounts Recognized on AEP’s Balance Sheets as of December 31, 2008 and 2007*

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td></td>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Employee Benefits and Pension Assets – Prepaid Benefit Costs</td>
<td>$ -</td>
<td>$482</td>
</tr>
<tr>
<td>Other Current Liabilities – Accrued Short-term Benefit Liability</td>
<td>(9)</td>
<td>(8)</td>
</tr>
<tr>
<td>Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability</td>
<td>(1,131)</td>
<td>(79)</td>
</tr>
<tr>
<td>Funded (Underfunded) Status</td>
<td>$(1,140)</td>
<td>$395</td>
</tr>
</tbody>
</table>
Components of the Change in AEP’s Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007 are as follows:

<table>
<thead>
<tr>
<th>Components of the Change in AEP’s Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007</th>
<th>2008</th>
<th>2007</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actuarial Loss (Gain) During the Year</td>
<td>$1,527</td>
<td>$(166)</td>
<td>$492</td>
<td>$(111)</td>
</tr>
<tr>
<td>Amortization of Actuarial Loss</td>
<td>(37)</td>
<td>(59)</td>
<td>(9)</td>
<td>(12)</td>
</tr>
<tr>
<td>Prior Service Cost (Credit)</td>
<td>(1)</td>
<td>19</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Amortization of Transition Obligation</td>
<td>-</td>
<td>-</td>
<td>(27)</td>
<td>(27)</td>
</tr>
<tr>
<td>Total Pretax AOCI Change for the Year</td>
<td>$1,489</td>
<td>$(206)</td>
<td>$456</td>
<td>$(150)</td>
</tr>
</tbody>
</table>

Pension and Other Postretirement Plans’ Assets

The asset allocations for AEP’s pension plans at the end of 2008 and 2007, and the target allocation for 2009 by asset category, are as follows:

<table>
<thead>
<tr>
<th>Asset Category</th>
<th>Target Allocation 2009</th>
<th>Percentage of Plan Assets at Year End 2008</th>
<th>Percentage of Plan Assets at Year End 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity Securities</td>
<td>55%</td>
<td>47%</td>
<td>57%</td>
</tr>
<tr>
<td>Real Estate</td>
<td>5%</td>
<td>6%</td>
<td>6%</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>39%</td>
<td>42%</td>
<td>36%</td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>1%</td>
<td>5%</td>
<td>1%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

The asset allocations for AEP’s OPEB plans at the end of 2008 and 2007, and target allocation for 2009 by asset category, are as follows:

<table>
<thead>
<tr>
<th>Asset Category</th>
<th>Target Allocation 2009</th>
<th>Percentage of Plan Assets at Year End 2008</th>
<th>Percentage of Plan Assets at Year End 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity Securities</td>
<td>65%</td>
<td>53%</td>
<td>62%</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>34%</td>
<td>43%</td>
<td>35%</td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>1%</td>
<td>4%</td>
<td>3%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>
AEP’s investment strategy for the employee benefit trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the plans’ assets relative to the plans’ liabilities. To minimize investment risk, AEP’s employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP’s targeted allocation when considered appropriate. AEP’s investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. AEP’s investment policies prohibit the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, AEP’s investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law, including ERISA.

The value of the pension plans’ assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007. The qualified plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of AEP’s OPEB plans’ assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007. The OPEB plans paid $120 million in benefits to plan participants during 2008.

AEP bases the determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

<table>
<thead>
<tr>
<th>December 31,</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulated Benefit Obligation (in millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Qualified Pension Plans</td>
<td>$4,119</td>
<td>$3,914</td>
</tr>
<tr>
<td>Nonqualified Pension Plans</td>
<td>80</td>
<td>77</td>
</tr>
<tr>
<td>Total</td>
<td>$4,199</td>
<td>$3,991</td>
</tr>
</tbody>
</table>

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2008 and 2007 were as follows:

<table>
<thead>
<tr>
<th>Underfunded Pension Plans</th>
<th>December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>Projected Benefit Obligation (in millions)</td>
<td></td>
</tr>
<tr>
<td>Accumulated Benefit Obligation</td>
<td>$4,301</td>
</tr>
<tr>
<td>Fair Value of Plan Assets</td>
<td>3,161</td>
</tr>
<tr>
<td>Underfunded Accumulated Benefit Obligation</td>
<td>$1,038</td>
</tr>
</tbody>
</table>

**Actuarial Assumptions for Benefit Obligations**

The weighted-average assumptions as of December 31, used in the measurement of AEP’s benefit obligations are shown in the following tables:

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumptions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Discount Rate</td>
<td>6.00%</td>
<td>6.00%</td>
</tr>
<tr>
<td>Rate of Compensation Increase</td>
<td>5.90%(a)</td>
<td>5.90%(a)</td>
</tr>
</tbody>
</table>

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

N/A = Not Applicable
To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody’s Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2008, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

### Estimated Future Benefit Payments and Contributions

Information about the 2009 expected cash flows for AEP’s pension (qualified and nonqualified) and OPEB plans is as follows:

<table>
<thead>
<tr>
<th>Employer Contributions</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required Contributions (a)</td>
<td>$</td>
<td>9</td>
</tr>
<tr>
<td>Additional Discretionary Contributions</td>
<td>-</td>
<td>158</td>
</tr>
</tbody>
</table>

(a) Contribution required to meet minimum funding requirement under ERISA plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB plans’ periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of AEP’s Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer’s assets, including both the employer’s share of the benefit cost and the participants’ share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for AEP’s pension benefits and OPEB are as follows:

<table>
<thead>
<tr>
<th>Year</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Benefit Payments</td>
<td>Medicare Subsidy Receipts</td>
</tr>
<tr>
<td>(in millions)</td>
<td>(in millions)</td>
<td>(in millions)</td>
</tr>
<tr>
<td>2009</td>
<td>$ 378</td>
<td>$ 116</td>
</tr>
<tr>
<td>2010</td>
<td>379</td>
<td>126</td>
</tr>
<tr>
<td>2011</td>
<td>377</td>
<td>136</td>
</tr>
<tr>
<td>2012</td>
<td>378</td>
<td>143</td>
</tr>
<tr>
<td>2013</td>
<td>384</td>
<td>151</td>
</tr>
<tr>
<td>Years 2014 to 2018, in Total</td>
<td>1,920</td>
<td>876</td>
</tr>
</tbody>
</table>
Components of Net Periodic Benefit Cost

The following table provides the components of AEP’s net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Components</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Cost</td>
<td>100</td>
<td>42</td>
</tr>
<tr>
<td>Interest Cost</td>
<td>249</td>
<td>113</td>
</tr>
<tr>
<td>Expected Return on Plan Assets</td>
<td>(336)</td>
<td>(111)</td>
</tr>
<tr>
<td>Amortization of Transition Obligation</td>
<td>-</td>
<td>27</td>
</tr>
<tr>
<td>Amortization of Prior Service Cost (Credit)</td>
<td>1</td>
<td>-</td>
</tr>
<tr>
<td>Amortization of Net Actuarial Loss</td>
<td>37</td>
<td>9</td>
</tr>
<tr>
<td>Net Periodic Benefit Cost</td>
<td>51</td>
<td>80</td>
</tr>
<tr>
<td>Capitalized Portion</td>
<td>(16)</td>
<td>9</td>
</tr>
<tr>
<td>Net Periodic Benefit Cost Recognized as Expense</td>
<td>$35</td>
<td>$55</td>
</tr>
</tbody>
</table>

Estimated amounts expected to be amortized to net periodic benefit costs for AEP’s plans during 2009 are shown in the following table:

<table>
<thead>
<tr>
<th>Components</th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Actuarial Loss</td>
<td>$56</td>
<td>$46</td>
</tr>
<tr>
<td>Prior Service Cost</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Transition Obligation</td>
<td>-</td>
<td>27</td>
</tr>
<tr>
<td>Total Estimated 2009 Pretax AOCI Amortization</td>
<td>$57</td>
<td>$74</td>
</tr>
<tr>
<td>Regulatory Asset</td>
<td>$46</td>
<td>$48</td>
</tr>
<tr>
<td>Deferred Income Taxes</td>
<td>4</td>
<td>9</td>
</tr>
<tr>
<td>Net of Tax AOCI</td>
<td>7</td>
<td>17</td>
</tr>
<tr>
<td>Total</td>
<td>$57</td>
<td>$74</td>
</tr>
</tbody>
</table>

Net Benefit Cost by Registrant

The following table provides the net periodic benefit cost (credit) for the plans by Registrant Subsidiary for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Components</th>
<th>Pension Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$3,337</td>
</tr>
<tr>
<td>CSPCo</td>
<td>(1,398)</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>7,283</td>
</tr>
<tr>
<td>OPCo</td>
<td>1,277</td>
</tr>
<tr>
<td>PSO</td>
<td>2,033</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>3,742</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Company</th>
<th>December 31, 2006</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$5,876</td>
<td>$14,896</td>
</tr>
<tr>
<td>CSPCo</td>
<td>820</td>
<td>6,041</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>9,319</td>
<td>9,765</td>
</tr>
<tr>
<td>OPCo</td>
<td>3,307</td>
<td>11,357</td>
</tr>
<tr>
<td>PSO</td>
<td>3,912</td>
<td>5,581</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>4,890</td>
<td>5,539</td>
</tr>
</tbody>
</table>
**Actuarial Assumptions for Net Periodic Benefit Costs**

The weighted-average assumptions as of January 1, used in the measurement of AEP’s benefit costs are shown in the following tables:

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount Rate</td>
<td>6.00%</td>
<td>5.75%</td>
</tr>
<tr>
<td>Expected Return on Plan Assets</td>
<td>8.00%</td>
<td>8.50%</td>
</tr>
<tr>
<td>Rate of Compensation Increase</td>
<td>5.90%</td>
<td>5.90%</td>
</tr>
</tbody>
</table>

N/A = Not Applicable

The expected return on plan assets for 2008 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for OPEB plans measurement purposes are shown below:

<table>
<thead>
<tr>
<th>Health Care Trend Rates</th>
<th>2008</th>
<th>2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial</td>
<td>7.0%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Ultimate</td>
<td>5.0%</td>
<td>5.0%</td>
</tr>
<tr>
<td>Year Ultimate Reached</td>
<td>2012</td>
<td>2012</td>
</tr>
</tbody>
</table>

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

<table>
<thead>
<tr>
<th>1% Increase (in millions)</th>
<th>1% Decrease (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Effect on Total Service and Interest Cost</td>
<td>Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation</td>
</tr>
<tr>
<td>Components of Net Periodic Postretirement Health Care Benefit Cost</td>
<td>$20</td>
</tr>
<tr>
<td>$196</td>
<td>(163)</td>
</tr>
</tbody>
</table>

**American Electric Power System Retirement Savings Plans**

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees who are not members of the United Mine Workers of America (UMWA). This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The amounts of contributions below for SWEPCo include a legacy savings plan of an acquired subsidiary.

The following table provides the cost for contributions to the retirement savings plans by the Registrant Subsidiaries for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31, 2008 (in thousands)</th>
<th>2007 (in thousands)</th>
<th>2006 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$8,226</td>
<td>$7,787</td>
<td>$7,471</td>
</tr>
<tr>
<td>CSPCo</td>
<td>3,678</td>
<td>3,442</td>
<td>3,224</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>9,501</td>
<td>9,075</td>
<td>8,764</td>
</tr>
<tr>
<td>OPCo</td>
<td>7,246</td>
<td>6,842</td>
<td>6,440</td>
</tr>
<tr>
<td>PSO</td>
<td>3,933</td>
<td>3,673</td>
<td>3,312</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>4,943</td>
<td>4,623</td>
<td>4,284</td>
</tr>
</tbody>
</table>
**UMWA Benefits**

APCo, CSPCo and OPCo provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by APCo, CSPCo and OPCo. Benefits are paid from their general assets. Contributions were not material in 2008, 2007 and 2006.

9. **NUCLEAR**

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. A significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant results from its ownership. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S.

**Decommissioning and Low Level Waste Accumulation Disposal**

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning study was performed in 2006. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $27 million in 2008, $32 million in 2007 and $30 million in 2006. Decommissioning costs recovered from customers are deposited in external trusts. The settlement agreement in I&M’s base rate case will reduce the annual decommissioning cost recovery amount effective in 2009 to reflect the extension of the units’ operating licenses granted by the NRC.

I&M deposited an additional $4 million in 2008, 2007 and 2006 in its decommissioning trust under funding provisions approved by regulatory commissions. At December 31, 2008 and 2007, the total decommissioning trust fund balance was $959 million and $1.1 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

**SNF Disposal**

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2008 and 2007, fees and related interest of $264 million and $259 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $301 million and $285 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.
Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at market value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. As discussed in the “Nuclear Trust Funds” section of Note 1, I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions’ liabilities. Regulatory approval is required to withdraw decommissioning funds.

See “SFAS 157 Fair Value Measurements” section of Note 11 for disclosure of the fair value of assets within the trust.

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

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2007</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Estimated</td>
<td>Gross</td>
<td>Other-Than-</td>
<td>Estimated</td>
<td>Gross</td>
</tr>
<tr>
<td></td>
<td>Fair Value</td>
<td>Unrealized</td>
<td>Temporary</td>
<td>Fair Value</td>
<td>Unrealized</td>
</tr>
<tr>
<td>(in millions)</td>
<td>(in millions)</td>
<td>Gains</td>
<td>Impairments</td>
<td>(in millions)</td>
<td>Gains</td>
</tr>
<tr>
<td>Cash</td>
<td>$ 18</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 22</td>
<td>$ -</td>
</tr>
<tr>
<td>Debt Securities</td>
<td>773</td>
<td>52</td>
<td>-3</td>
<td>823</td>
<td>27</td>
</tr>
<tr>
<td>Equity Securities</td>
<td>469</td>
<td>89</td>
<td>-82</td>
<td>502</td>
<td>205</td>
</tr>
<tr>
<td>Spent Nuclear Fuel and</td>
<td></td>
<td></td>
<td></td>
<td>$ 1,260</td>
<td>$ 232</td>
</tr>
<tr>
<td>Decommissioning Trusts</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Proceeds from sales of nuclear trust fund investments were $732 million, $696 million and $631 million in 2008, 2007 and 2006, respectively. Purchases of nuclear trust fund investments were $804 million, $777 million and $692 million in 2008, 2007 and 2006, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $33 million, $15 million and $7 million in 2008, 2007 and 2006, respectively. Gross realized losses from the sales of nuclear trust fund investments were $7 million, $5 million and $7 million in 2008, 2007 and 2006, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2008 was as follows:

<table>
<thead>
<tr>
<th></th>
<th>(in millions)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Within 1 year</td>
<td>$ 51</td>
<td></td>
</tr>
<tr>
<td>1 year – 5 years</td>
<td>172</td>
<td></td>
</tr>
<tr>
<td>5 years – 10 years</td>
<td>209</td>
<td></td>
</tr>
<tr>
<td>After 10 years</td>
<td>341</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$ 773</td>
<td></td>
</tr>
</tbody>
</table>

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for weekly indemnity payments resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. I&M’s participation in this mutual insurer requires a contingent financial obligation of up to $37 million which is assessable if the insurer’s financial resources would be inadequate to pay for losses.
The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.5 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $300 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.

10. BUSINESS SEGMENTS

The Registrant Subsidiaries have one reportable segment, an integrated electricity generation, transmission and distribution business. All of the Registrant Subsidiaries’ other activities are insignificant. The Registrant Subsidiaries’ operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

11. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract’s term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management’s approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the income statements on an accrual basis.

The Registrant Subsidiaries’ accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, the Registrant Subsidiaries designate a hedging instrument as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), the Registrant Subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in net income during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other
Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects net income. The Registrant Subsidiaries recognize hedge ineffectiveness in net income immediately during the period of change, except in regulated jurisdictions (APCo, I&M, PSO and the non-Texas portion of SWEPCo) where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the statements of income depending on the relevant facts and circumstances. However, unrealized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

**Fair Value Hedging Strategies**

At certain times, the Registrant Subsidiaries enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. The Registrant Subsidiaries record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on the statements of income. At various times during 2008, 2007 and 2006, APCo and I&M designated interest rate derivatives as fair value hedges and did not recognize any hedge ineffectiveness related to these derivative transactions.

**Cash Flow Hedging Strategies**

The Registrant Subsidiaries enter into, and designate as cash flow hedges, certain derivative transactions for the purchase and sale of electricity, coal and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the statements of income, depending on the specific nature of the risk being hedged. The Registrant Subsidiaries do not hedge all variable price risk exposure related to energy commodities. At various times during 2008, 2007 and 2006, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo designated cash flow hedge relationships using these commodities and recognized immaterial amounts in net income related to hedge ineffectiveness.

The Registrant Subsidiaries enter into various derivative instruments to manage interest rate exposure related to anticipated borrowings of fixed-rate debt, or to manage floating-rate debt exposure by converting it to a fixed rate. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. The Registrant Subsidiaries reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. At various times during 2008, 2007 and 2006, APCo, I&M, OPCo, PSO and SWEPCo designated interest rate derivatives as cash flow hedges and recognized immaterial amounts in net income due to hedge ineffectiveness.

At times, certain Registrant Subsidiaries are exposed to foreign currency exchange rate risks because they may purchase certain fixed assets from foreign suppliers. In accordance with AEP’s risk management policy, the Registrant Subsidiaries may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. The accumulated gains or losses related to these foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) into operating expenses over the as the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. At various times during 2008, 2007 and 2006, APCo, OPCo and SWEPCo designated foreign currency derivatives as cash flow hedges and did not recognize any hedge ineffectiveness related to these derivative transactions. The Registrant Subsidiaries do not hedge all foreign currency exposure.
The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2008:

<table>
<thead>
<tr>
<th>Company</th>
<th>APCo (in thousands)</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance at December 31, 2005</td>
<td>$16,421</td>
<td>$859</td>
<td>$3,467</td>
<td>$755</td>
<td>$1,112</td>
<td>$5,852</td>
</tr>
<tr>
<td>Effective Portion of Changes in Fair Value</td>
<td>10,365</td>
<td>3,438</td>
<td>6,576</td>
<td>6,899</td>
<td>728</td>
<td>1,833</td>
</tr>
<tr>
<td>Impact Due to Changes in SIA</td>
<td>442</td>
<td>261</td>
<td>267</td>
<td>337</td>
<td>506</td>
<td>592</td>
</tr>
<tr>
<td>Reclasses from AOCI to Net Income</td>
<td>3,951</td>
<td>1,080</td>
<td>1,348</td>
<td>55</td>
<td>264</td>
<td>683</td>
</tr>
<tr>
<td>Balance at December 31, 2006</td>
<td>$2,547</td>
<td>3,398</td>
<td>8,962</td>
<td>7,262</td>
<td>1,070</td>
<td>6,410</td>
</tr>
<tr>
<td>Effective Portion of Changes in Fair Value</td>
<td>781</td>
<td>831</td>
<td>834</td>
<td>1,485</td>
<td>-</td>
<td>416</td>
</tr>
<tr>
<td>Reclasses from AOCI to Net Income</td>
<td>4,178</td>
<td>3,217</td>
<td>2,355</td>
<td>4,620</td>
<td>183</td>
<td>805</td>
</tr>
<tr>
<td>Balance at December 31, 2007</td>
<td>$5,944</td>
<td>650</td>
<td>12,151</td>
<td>1,157</td>
<td>887</td>
<td>6,021</td>
</tr>
<tr>
<td>Effective Portion of Changes in Fair Value</td>
<td>423</td>
<td>1,445</td>
<td>1,399</td>
<td>965</td>
<td>-</td>
<td>187</td>
</tr>
<tr>
<td>Reclasses from AOCI to Net Income</td>
<td>975</td>
<td>736</td>
<td>1,713</td>
<td>1,528</td>
<td>183</td>
<td>284</td>
</tr>
<tr>
<td>Balance at December 31, 2008</td>
<td>$5,392</td>
<td>1,531</td>
<td>9,039</td>
<td>3,650</td>
<td>704</td>
<td>5,924</td>
</tr>
</tbody>
</table>

The following table approximates the net (loss) gain from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2008 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. In addition, the following table summarizes the maximum length of time that the variability of future cash flows is being hedged. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes.

<table>
<thead>
<tr>
<th>Company</th>
<th>Gain (Loss) Expected to be Reclassified to Net Income During the Next Twelve Months (in thousands)</th>
<th>Maximum Term for Exposure to Variability of Future Cash Flows (in months)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$959</td>
<td>24</td>
</tr>
<tr>
<td>CSPCo</td>
<td>1,476</td>
<td>24</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>422</td>
<td>24</td>
</tr>
<tr>
<td>OPCo</td>
<td>2,096</td>
<td>24</td>
</tr>
<tr>
<td>PSO</td>
<td>(183)</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>(829)</td>
<td>47</td>
</tr>
</tbody>
</table>

**Credit Risk**

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. The Registrant Subsidiaries limit their credit risk by maintaining stringent credit policies whereby the Registrant Subsidiaries assess a counterparty’s creditworthiness prior to transacting with them and continue to assess their creditworthiness on an ongoing basis. The Registrant Subsidiaries employ the use of standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure is exceeded in excess of an established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP’s credit policy. In addition, collateral agreements also provide that the failure or inability to post collateral is sufficient cause for termination and liquidation of all positions.
FAIR VALUE MEASUREMENTS

SFAS 107 Fair Value Measurements

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries at December 31, 2008 and 2007 are summarized in the following table:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$3,174,512</td>
<td>$2,858,278</td>
<td>$2,847,299</td>
<td>$2,811,067</td>
<td>$2,811,067</td>
<td>$2,811,067</td>
</tr>
<tr>
<td>CSPCo</td>
<td>1,443,594</td>
<td>1,410,609</td>
<td>1,298,224</td>
<td>1,290,718</td>
<td>1,290,718</td>
<td>1,290,718</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>1,377,914</td>
<td>1,308,712</td>
<td>1,567,427</td>
<td>1,527,320</td>
<td>1,527,320</td>
<td>1,527,320</td>
</tr>
<tr>
<td>OPCo</td>
<td>3,039,376</td>
<td>2,953,131</td>
<td>2,849,598</td>
<td>2,865,214</td>
<td>2,865,214</td>
<td>2,865,214</td>
</tr>
<tr>
<td>PSO</td>
<td>884,859</td>
<td>823,150</td>
<td>918,316</td>
<td>913,432</td>
<td>913,432</td>
<td>913,432</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,478,149</td>
<td>1,358,122</td>
<td>1,197,217</td>
<td>1,190,708</td>
<td>1,190,708</td>
<td>1,190,708</td>
</tr>
</tbody>
</table>

SFAS 157 Fair Value Measurements

As described in Note 2, the Registrant Subsidiaries completed the adoption of SFAS 157 effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on the Registrant Subsidiaries’ financial statements. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF Issue No. 02-3 “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (EITF 02-3), b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, APCo, CSPCo and OPCo reduced beginning retained earnings by $440 thousand ($286 thousand, net of tax), $486 thousand ($316 thousand, net of tax), respectively, for the transition adjustment. SWEPCo’s transition adjustment was a favorable $16 thousand ($10 thousand, net of tax) adjustment to beginning retained earnings. The impact of considering AEP’s credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption.

In accordance with SFAS 157, assets and liabilities are classified based on the inputs utilized in the fair value measurement. SFAS 157 provides definitions for two types of inputs: observable and unobservable. Observable inputs are valuation inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are valuation inputs that reflect the reporting entity’s own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information in the circumstances.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
Level 2 inputs are inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivative fair values are verified using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets, or valued using pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer’s energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. Management uses a consistent modeling approach to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data), and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. In certain instances, the fair values of the transactions included in level 3 that use internally developed model inputs are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.
The following table sets forth by level within the fair value hierarchy the Registrant Subsidiaries’ financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

### Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

#### APCo

<table>
<thead>
<tr>
<th></th>
<th>Level 1</th>
<th>Level 2</th>
<th>Level 3 (in thousands)</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assets:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Cash Deposits (d)</td>
<td>656</td>
<td>-</td>
<td>-</td>
<td>52</td>
<td>708</td>
</tr>
<tr>
<td><strong>Risk Management Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>16,105</td>
<td>667,748</td>
<td>11,981</td>
<td>(597,676)</td>
<td>98,158</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>6,634</td>
<td>-</td>
<td>(1,413)</td>
<td>5,221</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (b)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>12,856</td>
<td>12,856</td>
</tr>
<tr>
<td><strong>Total Risk Management Assets</strong></td>
<td>16,105</td>
<td>674,382</td>
<td>11,981</td>
<td>(586,233)</td>
<td>116,235</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>16,761</td>
<td>674,382</td>
<td>11,981</td>
<td>(586,181)</td>
<td>116,943</td>
</tr>
<tr>
<td><strong>Liabilities:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Risk Management Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>18,808</td>
<td>628,974</td>
<td>3,972</td>
<td>(601,108)</td>
<td>50,646</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>2,545</td>
<td>-</td>
<td>(1,413)</td>
<td>1,132</td>
</tr>
<tr>
<td>DETM Assignment (c)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>5,230</td>
<td>5,230</td>
</tr>
<tr>
<td><strong>Total Risk Management Liabilities</strong></td>
<td>18,808</td>
<td>631,519</td>
<td>3,972</td>
<td>(597,291)</td>
<td>57,008</td>
</tr>
</tbody>
</table>

#### CSPCo

<table>
<thead>
<tr>
<th></th>
<th>Level 1</th>
<th>Level 2</th>
<th>Level 3 (in thousands)</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assets:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Cash Deposits (d)</td>
<td>31,129</td>
<td>-</td>
<td>-</td>
<td>1,171</td>
<td>32,300</td>
</tr>
<tr>
<td><strong>Risk Management Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>9,042</td>
<td>366,557</td>
<td>6,724</td>
<td>(328,027)</td>
<td>54,296</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>3,725</td>
<td>-</td>
<td>(794)</td>
<td>2,931</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (b)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>7,218</td>
<td>7,218</td>
</tr>
<tr>
<td><strong>Total Risk Management Assets</strong></td>
<td>9,042</td>
<td>370,282</td>
<td>6,724</td>
<td>(321,603)</td>
<td>64,445</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>40,171</td>
<td>370,282</td>
<td>6,724</td>
<td>(320,432)</td>
<td>96,745</td>
</tr>
<tr>
<td><strong>Liabilities:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Risk Management Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>10,559</td>
<td>344,860</td>
<td>2,227</td>
<td>(329,954)</td>
<td>27,692</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>1,429</td>
<td>-</td>
<td>(794)</td>
<td>635</td>
</tr>
<tr>
<td>DETM Assignment (c)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2,937</td>
<td>2,937</td>
</tr>
<tr>
<td><strong>Total Risk Management Liabilities</strong></td>
<td>10,559</td>
<td>346,289</td>
<td>2,227</td>
<td>(327,811)</td>
<td>31,264</td>
</tr>
</tbody>
</table>
### I&M

<table>
<thead>
<tr>
<th>Assets:</th>
<th>Level 1</th>
<th>Level 2</th>
<th>Level 3 (in thousands)</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Risk Management Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$ 8,750</td>
<td>$ 357,405</td>
<td>$ 6,508</td>
<td>(319,857)</td>
<td>$ 52,806</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>3,605</td>
<td>-</td>
<td>(768)</td>
<td>2,837</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (b)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>6,985</td>
<td>6,985</td>
</tr>
<tr>
<td><strong>Total Risk Management Assets</strong></td>
<td>8,750</td>
<td>361,010</td>
<td>6,508</td>
<td>(313,640)</td>
<td>62,628</td>
</tr>
<tr>
<td><strong>Spent Nuclear Fuel and Decommissioning Trusts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents (e)</td>
<td>-</td>
<td>7,818</td>
<td>-</td>
<td>11,845</td>
<td>19,663</td>
</tr>
<tr>
<td>Debt Securities (f)</td>
<td>-</td>
<td>771,216</td>
<td>-</td>
<td>-</td>
<td>771,216</td>
</tr>
<tr>
<td>Equity Securities (g)</td>
<td>468,654</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>468,654</td>
</tr>
<tr>
<td><strong>Total Spent Nuclear Fuel and Decommissioning Trusts</strong></td>
<td>468,654</td>
<td>779,034</td>
<td>-</td>
<td>11,845</td>
<td>1,259,533</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$ 477,404</td>
<td>$ 1,140,044</td>
<td>$ 6,508</td>
<td>(301,795)</td>
<td>$ 1,322,161</td>
</tr>
</tbody>
</table>

### Liabilities:

<table>
<thead>
<tr>
<th>Liabilities:</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Risk Management Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$ 10,219</td>
<td>$ 336,280</td>
<td>$ 2,156</td>
<td>(321,722)</td>
<td>$ 26,933</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>1,383</td>
<td>-</td>
<td>(768)</td>
<td>615</td>
</tr>
<tr>
<td>DETM Assignment (c)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2,842</td>
<td>2,842</td>
</tr>
<tr>
<td><strong>Total Risk Management Liabilities</strong></td>
<td>$ 10,219</td>
<td>$ 337,663</td>
<td>$ 2,156</td>
<td>(319,648)</td>
<td>$ 30,390</td>
</tr>
</tbody>
</table>

### OPCo

<table>
<thead>
<tr>
<th>Assets:</th>
<th>Level 1</th>
<th>Level 2</th>
<th>Level 3 (in thousands)</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other Cash Deposits (e)</td>
<td>$ 4,197</td>
<td>-</td>
<td>$ -</td>
<td>$ 2,431</td>
<td>$ 6,628</td>
</tr>
<tr>
<td><strong>Risk Management Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>11,200</td>
<td>575,415</td>
<td>8,364</td>
<td>(515,162)</td>
<td>79,817</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>4,614</td>
<td>-</td>
<td>(983)</td>
<td>3,631</td>
</tr>
<tr>
<td>Dedesignated Risk Management Contracts (b)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>8,941</td>
<td>8,941</td>
</tr>
<tr>
<td><strong>Total Risk Management Assets</strong></td>
<td>11,200</td>
<td>580,029</td>
<td>8,364</td>
<td>(507,204)</td>
<td>92,389</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$ 15,397</td>
<td>$ 580,029</td>
<td>$ 8,364</td>
<td>(504,773)</td>
<td>$ 99,017</td>
</tr>
</tbody>
</table>

### Liabilities:

<table>
<thead>
<tr>
<th>Liabilities:</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Risk Management Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$ 13,080</td>
<td>$ 550,278</td>
<td>$ 2,801</td>
<td>(517,548)</td>
<td>$ 48,611</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>1,770</td>
<td>-</td>
<td>(983)</td>
<td>787</td>
</tr>
<tr>
<td>DETM Assignment (c)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3,637</td>
<td>3,637</td>
</tr>
<tr>
<td><strong>Total Risk Management Liabilities</strong></td>
<td>$ 13,080</td>
<td>$ 552,048</td>
<td>$ 2,801</td>
<td>(514,894)</td>
<td>$ 53,035</td>
</tr>
</tbody>
</table>
### PSO

**Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008**

<table>
<thead>
<tr>
<th></th>
<th>Level 1 (in thousands)</th>
<th>Level 2</th>
<th>Level 3</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assets:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$3,295</td>
<td>$39,866</td>
<td>$8</td>
<td>$(36,422)</td>
<td>$6,747</td>
</tr>
<tr>
<td>Liabilities:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$3,664</td>
<td>$37,835</td>
<td>$10</td>
<td>$(36,527)</td>
<td>$4,982</td>
</tr>
<tr>
<td>DETM Assignment (c)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>149</td>
<td>149</td>
</tr>
<tr>
<td><strong>Total Risk Management Liabilities</strong></td>
<td>$3,664</td>
<td>$37,835</td>
<td>$10</td>
<td>$(36,378)</td>
<td>$5,131</td>
</tr>
</tbody>
</table>

(a) Amounts in “Other” column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) “Dedesignated Risk Management Contracts” are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See “Natural Gas Contracts with DETM” section of Note 15.

(d) Amounts in “Other” column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

(e) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(f) Amounts represent corporate, municipal and treasury bonds.

(g) Amounts represent publicly traded equity securities and equity-based mutual funds.

### SWEPCo

**Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008**

<table>
<thead>
<tr>
<th></th>
<th>Level 1 (in thousands)</th>
<th>Level 2</th>
<th>Level 3</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assets:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$3,883</td>
<td>$61,471</td>
<td>$14</td>
<td>$(55,710)</td>
<td>$9,658</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>107</td>
<td>-</td>
<td>(80)</td>
<td>27</td>
</tr>
<tr>
<td><strong>Total Risk Management Assets</strong></td>
<td>$3,883</td>
<td>$61,578</td>
<td>$14</td>
<td>$(55,790)</td>
<td>$9,685</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Level 1 (in thousands)</th>
<th>Level 2</th>
<th>Level 3</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Liabilities:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Risk Management Contracts (a)</td>
<td>$4,318</td>
<td>$58,390</td>
<td>$17</td>
<td>$(55,834)</td>
<td>$6,891</td>
</tr>
<tr>
<td>Cash Flow and Fair Value Hedges (a)</td>
<td>-</td>
<td>265</td>
<td>-</td>
<td>(80)</td>
<td>185</td>
</tr>
<tr>
<td>DETM Assignment (c)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>175</td>
<td>175</td>
</tr>
<tr>
<td><strong>Total Risk Management Liabilities</strong></td>
<td>$4,318</td>
<td>$58,655</td>
<td>$17</td>
<td>$(55,739)</td>
<td>$7,251</td>
</tr>
</tbody>
</table>

(a) Amounts in “Other” column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) “Dedesignated Risk Management Contracts” are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See “Natural Gas Contracts with DETM” section of Note 15.

(d) Amounts in “Other” column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

(e) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(f) Amounts represent corporate, municipal and treasury bonds.

(g) Amounts represent publicly traded equity securities and equity-based mutual funds.
The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as level 3 in the fair value hierarchy:

<table>
<thead>
<tr>
<th>Year Ended December 31, 2008</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance as of January 1, 2008</td>
<td>$ (697)</td>
<td>$ (263)</td>
<td>$ (280)</td>
<td>$ (1,607)</td>
<td>$ (243)</td>
<td>$ (408)</td>
</tr>
<tr>
<td>Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)</td>
<td>393</td>
<td>86</td>
<td>110</td>
<td>1,406</td>
<td>244</td>
<td>410</td>
</tr>
<tr>
<td>Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)</td>
<td>-</td>
<td>1,724</td>
<td>-</td>
<td>2,082</td>
<td>-</td>
<td>(1)</td>
</tr>
<tr>
<td>Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Purchases, Issuances and Settlements</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Transfers in and/or out of Level 3 (b)</td>
<td>(931)</td>
<td>(537)</td>
<td>(516)</td>
<td>(637)</td>
<td>(1)</td>
<td>(2)</td>
</tr>
<tr>
<td>Changes in Fair Value Allocated to Regulated Jurisdictions (c)</td>
<td>9,244</td>
<td>3,487</td>
<td>5,038</td>
<td>4,319</td>
<td>(2)</td>
<td>(2)</td>
</tr>
<tr>
<td><strong>Balance as of December 31, 2008</strong></td>
<td>$ 8,009</td>
<td>$ 4,497</td>
<td>$ 4,352</td>
<td>$ 5,563</td>
<td>$ (2)</td>
<td>$ (3)</td>
</tr>
</tbody>
</table>

(a) Included in revenues on the Statements of Income.
(b) “Transfers in and/or out of Level 3” represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(c) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected on the Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

**12. INCOME TAXES**

The details of the Registrant Subsidiaries’ income taxes before extraordinary loss as reported are as follows:

<table>
<thead>
<tr>
<th>Year Ended December 31, 2008</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax Expense (Credit):</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>(97,447)</td>
<td>$ 111,996</td>
<td>$ 2,575</td>
<td>$ 72,847</td>
<td>(24,763)</td>
<td>$ (25,055)</td>
</tr>
<tr>
<td>Deferred</td>
<td>145,594</td>
<td>(303)</td>
<td>57,879</td>
<td>42,717</td>
<td>67,874</td>
<td>62,060</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>(4,209)</td>
<td>(1,954)</td>
<td>(2,196)</td>
<td>(942)</td>
<td>(834)</td>
<td>(3,964)</td>
</tr>
<tr>
<td><strong>Total Income Tax</strong></td>
<td>$ 43,938</td>
<td>$ 109,739</td>
<td>$ 58,258</td>
<td>$ 114,622</td>
<td>$ 42,277</td>
<td>$ 33,041</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year Ended December 31, 2007</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax Expense (Credit):</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>$ 17,254</td>
<td>$ 152,443</td>
<td>$ 68,402</td>
<td>$ 134,935</td>
<td>$ 52,670</td>
<td>$ 43,659</td>
</tr>
<tr>
<td>Deferred</td>
<td>48,962</td>
<td>(20,874)</td>
<td>4,177</td>
<td>16,238</td>
<td>31,362</td>
<td>(21,935)</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>(4,102)</td>
<td>(1,954)</td>
<td>(2,196)</td>
<td>(942)</td>
<td>(834)</td>
<td>(3,964)</td>
</tr>
<tr>
<td><strong>Total Income Tax</strong></td>
<td>$ 62,114</td>
<td>$ 129,385</td>
<td>$ 67,499</td>
<td>$ 148,585</td>
<td>$ 22,015</td>
<td>$ 17,561</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year Ended December 31, 2006</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax Expense (Credit):</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current</td>
<td>$ 88,750</td>
<td>$ 114,007</td>
<td>$ 70,231</td>
<td>$ 165,290</td>
<td>$ 40,690</td>
<td>$ 71,589</td>
</tr>
<tr>
<td>Deferred</td>
<td>17,225</td>
<td>(10,900)</td>
<td>13,626</td>
<td>(43,997)</td>
<td>(23,672)</td>
<td>(23,667)</td>
</tr>
<tr>
<td>Deferred Investment Tax Credits</td>
<td>(4,559)</td>
<td>(2,264)</td>
<td>(7,752)</td>
<td>(2,969)</td>
<td>(1,031)</td>
<td>(4,225)</td>
</tr>
<tr>
<td><strong>Total Income Tax</strong></td>
<td>$ 101,416</td>
<td>$ 100,843</td>
<td>$ 76,105</td>
<td>$ 118,324</td>
<td>$ 15,987</td>
<td>$ 43,697</td>
</tr>
</tbody>
</table>
Shown below is a reconciliation for each Registrant Subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

<table>
<thead>
<tr>
<th>Registrant Subsidiary</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$ 122,863</td>
<td>$ 237,130</td>
<td>$ 131,875</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>43,938</td>
<td>109,739</td>
<td>58,258</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td>$ 166,801</td>
<td>$ 346,869</td>
<td>$ 190,133</td>
</tr>
<tr>
<td>Income Tax on Pretax Income at Statutory Rate (35%)</td>
<td>$ 58,380</td>
<td>$ 121,404</td>
<td>$ 66,547</td>
</tr>
<tr>
<td>Increase (Decrease) in Income Tax resulting from the following items:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>9,117</td>
<td>3,659</td>
<td>4,971</td>
</tr>
<tr>
<td>Nuclear Fuel Disposal Costs</td>
<td>-</td>
<td>-</td>
<td>(4,381)</td>
</tr>
<tr>
<td>Allowance for Funds Used During Construction</td>
<td>(6,159)</td>
<td>(1,372)</td>
<td>(3,362)</td>
</tr>
<tr>
<td>Rockport Plant Unit 2 Investment Tax Credit</td>
<td>-</td>
<td>-</td>
<td>397</td>
</tr>
<tr>
<td>Removal Costs</td>
<td>(6,596)</td>
<td>(806)</td>
<td>(3,839)</td>
</tr>
<tr>
<td>Investment Tax Credits, Net</td>
<td>(4,209)</td>
<td>(1,954)</td>
<td>(2,196)</td>
</tr>
<tr>
<td>State and Local Income Taxes</td>
<td>(7,583)</td>
<td>964</td>
<td>3,077</td>
</tr>
<tr>
<td>Parent Company Loss Benefit</td>
<td>(29)</td>
<td>(6,663)</td>
<td>(1,023)</td>
</tr>
<tr>
<td>Other</td>
<td>1,017</td>
<td>(5,493)</td>
<td>(1,933)</td>
</tr>
<tr>
<td><strong>Total Income Taxes</strong></td>
<td>$ 43,938</td>
<td>$ 109,739</td>
<td>$ 58,258</td>
</tr>
<tr>
<td><strong>Effective Income Tax Rate</strong></td>
<td>26.3%</td>
<td>31.6%</td>
<td>30.6%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Registrant Subsidiary</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$ 231,123</td>
<td>$ 78,484</td>
<td>$ 92,754</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>114,622</td>
<td>42,277</td>
<td>33,041</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td>$ 345,745</td>
<td>$ 120,761</td>
<td>$ 125,795</td>
</tr>
<tr>
<td>Income Tax on Pretax Income at Statutory Rate (35%)</td>
<td>$ 121,011</td>
<td>$ 42,266</td>
<td>$ 44,028</td>
</tr>
<tr>
<td>Increase (Decrease) in Income Tax resulting from the following items:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>4,389</td>
<td>(502)</td>
<td>502</td>
</tr>
<tr>
<td>Depletion</td>
<td>-</td>
<td>-</td>
<td>(3,158)</td>
</tr>
<tr>
<td>Allowance for Funds Used During Construction</td>
<td>(1,555)</td>
<td>(587)</td>
<td>(5,114)</td>
</tr>
<tr>
<td>Investment Tax Credits, Net</td>
<td>(942)</td>
<td>(834)</td>
<td>(3,964)</td>
</tr>
<tr>
<td>State and Local Income Taxes</td>
<td>2,102</td>
<td>3,845</td>
<td>4,121</td>
</tr>
<tr>
<td>Other</td>
<td>(10,383)</td>
<td>(1,911)</td>
<td>(3,374)</td>
</tr>
<tr>
<td><strong>Total Income Taxes</strong></td>
<td>$ 114,622</td>
<td>$ 42,277</td>
<td>$ 33,041</td>
</tr>
<tr>
<td><strong>Effective Income Tax Rate</strong></td>
<td>33.2%</td>
<td>35.0%</td>
<td>26.3%</td>
</tr>
</tbody>
</table>
### Year Ended December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$ 54,736</td>
<td>$ 258,088</td>
<td>$ 136,895</td>
</tr>
<tr>
<td>Extraordinary Loss</td>
<td>78,763</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>62,114</td>
<td>129,385</td>
<td>67,499</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td><strong>$ 195,613</strong></td>
<td><strong>$ 387,473</strong></td>
<td><strong>$ 204,394</strong></td>
</tr>
<tr>
<td>Income Tax on Pretax Income at Statutory Rate (35%)</td>
<td>$ 68,465</td>
<td>$ 135,616</td>
<td>$ 71,538</td>
</tr>
<tr>
<td>Increase (Decrease) in Income Tax resulting from the following items:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>8,015</td>
<td>4,298</td>
<td>14,251</td>
</tr>
<tr>
<td>Nuclear Fuel Disposal Costs</td>
<td>-</td>
<td>-</td>
<td>(5,610)</td>
</tr>
<tr>
<td>Allowance for Funds Used During Construction</td>
<td>(4,334)</td>
<td>(1,223)</td>
<td>(4,376)</td>
</tr>
<tr>
<td>Rockport Plant Unit 2 Investment Tax Credit</td>
<td>-</td>
<td>-</td>
<td>397</td>
</tr>
<tr>
<td>Removal Costs</td>
<td>(5,394)</td>
<td>(917)</td>
<td>(8,191)</td>
</tr>
<tr>
<td>Investment Tax Credits, Net</td>
<td>(4,102)</td>
<td>(2,184)</td>
<td>(5,080)</td>
</tr>
<tr>
<td>State and Local Income Taxes</td>
<td>1,706</td>
<td>(4,096)</td>
<td>3,663</td>
</tr>
<tr>
<td>Parent Company Loss Benefit</td>
<td>(370)</td>
<td>(2,160)</td>
<td>(925)</td>
</tr>
<tr>
<td>Other</td>
<td>(1,872)</td>
<td>51</td>
<td>1,832</td>
</tr>
<tr>
<td><strong>Total Income Taxes</strong></td>
<td><strong>$ 62,114</strong></td>
<td><strong>$ 129,385</strong></td>
<td><strong>$ 67,499</strong></td>
</tr>
<tr>
<td>Effective Income Tax Rate</td>
<td>31.8%</td>
<td>33.4%</td>
<td>33.0%</td>
</tr>
</tbody>
</table>

### Year Ended December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income (Loss)</td>
<td>$ 268,564</td>
<td>$(24,124)</td>
<td>$ 66,264</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>148,585</td>
<td>(22,015)</td>
<td>17,561</td>
</tr>
<tr>
<td><strong>Pretax Income (Loss)</strong></td>
<td><strong>$ 417,149</strong></td>
<td><strong>$(46,139)</strong></td>
<td><strong>$ 83,825</strong></td>
</tr>
<tr>
<td>Income Tax on Pretax Income at Statutory Rate (35%)</td>
<td>$ 146,002</td>
<td>$(16,149)</td>
<td>$ 29,339</td>
</tr>
<tr>
<td>Increase (Decrease) in Income Tax resulting from the following items:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>2,362</td>
<td>(592)</td>
<td>17</td>
</tr>
<tr>
<td>Depletion</td>
<td>-</td>
<td>-</td>
<td>(3,360)</td>
</tr>
<tr>
<td>Allowance for Funds Used During Construction</td>
<td>(1,269)</td>
<td>(433)</td>
<td>(3,490)</td>
</tr>
<tr>
<td>Investment Tax Credits, Net</td>
<td>(2,588)</td>
<td>(707)</td>
<td>(4,163)</td>
</tr>
<tr>
<td>State and Local Income Taxes</td>
<td>3,438</td>
<td>(3,699)</td>
<td>(165)</td>
</tr>
<tr>
<td>Other</td>
<td>640</td>
<td>(435)</td>
<td>(617)</td>
</tr>
<tr>
<td><strong>Total Income Taxes</strong></td>
<td><strong>$ 148,585</strong></td>
<td><strong>$(22,015)</strong></td>
<td><strong>$ 17,561</strong></td>
</tr>
<tr>
<td>Effective Income Tax Rate</td>
<td>35.6%</td>
<td>47.7%</td>
<td>20.9%</td>
</tr>
</tbody>
</table>
### APCo, CSPCo, I&M

<table>
<thead>
<tr>
<th></th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2006</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$181,449</td>
<td>$185,579</td>
<td>$121,168</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>101,416</td>
<td>100,843</td>
<td>76,105</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td>$282,865</td>
<td>$286,422</td>
<td>$197,273</td>
</tr>
</tbody>
</table>

Income Tax on Pretax Income at Statutory Rate (35%)

Increase (Decrease) in Income Tax resulting from the following items:

- **Depreciation**: 10,325, 1,395, 20,834
- **Nuclear Fuel Disposal Costs**: -7,379, 1,328, 20,834
- **Allowance for Funds Used During Construction**: (7,379), (789), (5,149)
- **Rockport Plant Unit 2 Investment Tax Credit**: -3,339, -544, 397
- **Removal Costs**: (3,339), (544), (5,968)

**Total Income Taxes**

<table>
<thead>
<tr>
<th></th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2006</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$228,643</td>
<td>$36,860</td>
<td>$91,723</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>118,324</td>
<td>15,987</td>
<td>43,697</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td>$346,967</td>
<td>$52,847</td>
<td>$135,420</td>
</tr>
</tbody>
</table>

Income Tax on Pretax Income at Statutory Rate (35%)

Increase (Decrease) in Income Tax resulting from the following items:

- **Depreciation**: 4,397, (593), (85)
- **Depletion**: -1,323, (209), (370)
- **Allowance for Funds Used During Construction**: (2,969), (1,031), (4,225)
- **Investment Tax Credits, Net**: 270, 260, 3,764
- **State and Local Income Taxes**: (3,489), (936), 366

**Total Income Taxes**

<table>
<thead>
<tr>
<th></th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Effective Income Tax Rate</td>
<td>35.9%</td>
<td>35.2%</td>
<td>38.6%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Year Ended December 31, 2006</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Income</td>
<td>$181,449</td>
<td>$185,579</td>
<td>$121,168</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>101,416</td>
<td>100,843</td>
<td>76,105</td>
</tr>
<tr>
<td><strong>Pretax Income</strong></td>
<td>$282,865</td>
<td>$286,422</td>
<td>$197,273</td>
</tr>
</tbody>
</table>

Income Tax on Pretax Income at Statutory Rate (35%)

Increase (Decrease) in Income Tax resulting from the following items:

- **Depreciation**: 4,397, (593), (85)
- **Depletion**: -1,323, (209), (370)
- **Allowance for Funds Used During Construction**: (2,969), (1,031), (4,225)
- **Investment Tax Credits, Net**: 270, 260, 3,764
- **State and Local Income Taxes**: (3,489), (936), 366

**Total Income Taxes**

<table>
<thead>
<tr>
<th></th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Effective Income Tax Rate</td>
<td>34.1%</td>
<td>30.3%</td>
<td>32.3%</td>
</tr>
</tbody>
</table>
The following tables show the elements of the net deferred tax liability and the significant temporary differences for each Registrant Subsidiary:

### December 31, 2008

<table>
<thead>
<tr>
<th></th>
<th>APCo (in thousands)</th>
<th>CSPCo (in thousands)</th>
<th>I&amp;M (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Deferred Tax Assets</strong></td>
<td>$432,117</td>
<td>$154,855</td>
<td>$490,673</td>
</tr>
<tr>
<td><strong>Deferred Tax Liabilities</strong></td>
<td>(1,550,579)</td>
<td>(584,866)</td>
<td>(886,764)</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td>$(1,118,462)</td>
<td>$(430,011)</td>
<td>$(396,091)</td>
</tr>
<tr>
<td><strong>Property Related Temporary Differences</strong></td>
<td>$(810,749)</td>
<td>$(406,952)</td>
<td>$(93,085)</td>
</tr>
<tr>
<td><strong>Amounts Due from Customers for Future Federal Income Taxes</strong></td>
<td>$(103,558)</td>
<td>(4,789)</td>
<td>(24,128)</td>
</tr>
<tr>
<td><strong>Deferred State Income Taxes</strong></td>
<td>$(142,558)</td>
<td>(5,403)</td>
<td>(47,922)</td>
</tr>
<tr>
<td><strong>Transition Regulatory Assets</strong></td>
<td>(2,971)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Deferred Income Taxes on Other Comprehensive Loss</strong></td>
<td>32,429</td>
<td>27,475</td>
<td>11,681</td>
</tr>
<tr>
<td><strong>Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2</strong></td>
<td>-</td>
<td>-</td>
<td>17,411</td>
</tr>
<tr>
<td><strong>Accrued Nuclear Decommissioning Expense</strong></td>
<td>(57,102)</td>
<td>-</td>
<td>(275,615)</td>
</tr>
<tr>
<td><strong>Deferred Fuel and Purchased Power</strong></td>
<td>54,564</td>
<td>10,206</td>
<td>42,894</td>
</tr>
<tr>
<td><strong>Accrued Pensions</strong></td>
<td>54,564</td>
<td>10,206</td>
<td>42,894</td>
</tr>
<tr>
<td><strong>Nuclear Fuel</strong></td>
<td>-</td>
<td>-</td>
<td>(8,738)</td>
</tr>
<tr>
<td><strong>Regulatory Assets</strong></td>
<td>(182,831)</td>
<td>(75,520)</td>
<td>(94,181)</td>
</tr>
<tr>
<td><strong>All Other, Net</strong></td>
<td>94,314</td>
<td>24,972</td>
<td>66,007</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td>$(1,118,462)</td>
<td>$(430,011)</td>
<td>$(396,091)</td>
</tr>
</tbody>
</table>

### December 31, 2008

<table>
<thead>
<tr>
<th></th>
<th>OPCo (in thousands)</th>
<th>PSO (in thousands)</th>
<th>SWEPCo (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Deferred Tax Assets</strong></td>
<td>$322,089</td>
<td>$82,852</td>
<td>$49,950</td>
</tr>
<tr>
<td><strong>Deferred Tax Liabilities</strong></td>
<td>(1,240,032)</td>
<td>(588,449)</td>
<td>(454,352)</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td>$(917,943)</td>
<td>$(505,597)</td>
<td>$(404,402)</td>
</tr>
<tr>
<td><strong>Property Related Temporary Differences</strong></td>
<td>$(881,967)</td>
<td>$(426,221)</td>
<td>$(345,145)</td>
</tr>
<tr>
<td><strong>Amounts Due from Customers for Future Federal Income Taxes</strong></td>
<td>$(55,181)</td>
<td>2,477</td>
<td>(7,739)</td>
</tr>
<tr>
<td><strong>Deferred State Income Taxes</strong></td>
<td>(49,199)</td>
<td>(53,258)</td>
<td>(22,221)</td>
</tr>
<tr>
<td><strong>Transition Regulatory Assets</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Deferred Income Taxes on Other Comprehensive Loss</strong></td>
<td>72,014</td>
<td>379</td>
<td>17,296</td>
</tr>
<tr>
<td><strong>Deferred Fuel and Purchased Power</strong></td>
<td>-</td>
<td>(50)</td>
<td>(29,641)</td>
</tr>
<tr>
<td><strong>Accrued Pensions</strong></td>
<td>720</td>
<td>19,914</td>
<td>11,223</td>
</tr>
<tr>
<td><strong>Regulatory Assets</strong></td>
<td>(82,044)</td>
<td>(79,869)</td>
<td>(45,059)</td>
</tr>
<tr>
<td><strong>All Other, Net</strong></td>
<td>77,714</td>
<td>31,031</td>
<td>16,884</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td>$(917,943)</td>
<td>$(505,597)</td>
<td>$(404,402)</td>
</tr>
</tbody>
</table>
### December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Deferred Tax Assets</strong></td>
<td>$320,186</td>
<td>$104,680</td>
<td>$694,293</td>
</tr>
<tr>
<td><strong>Deferred Tax Liabilities</strong></td>
<td>(1,292,189)</td>
<td>(553,665)</td>
<td>(1,023,778)</td>
</tr>
<tr>
<td><strong>Net Deferred Tax Liabilities</strong></td>
<td>$ (972,003)</td>
<td>$ (448,985)</td>
<td>$ (329,485)</td>
</tr>
</tbody>
</table>

- **Property Related Temporary Differences**
  - APCo: $(729,960)$
  - CSPCo: $(375,433)$
  - I&M: $17,170$

- **Amounts Due from Customers for Future Federal Income Taxes**
  - APCo: $(103,488)$
  - CSPCo: $(4,803)$
  - I&M: $(23,509)$

- **Deferred State Income Taxes**
  - APCo: $(109,997)$
  - CSPCo: $(7,198)$
  - I&M: $(38,345)$

- **Transition Regulatory Assets**
  - APCo: $(4,457)$
  - CSPCo: $(17,290)$
  - I&M: $-$

- **Deferred Income Taxes on Other Comprehensive Loss**
  - APCo: $18,947$
  - CSPCo: $10,120$
  - I&M: $8,440$

- **Accrued Nuclear Decommissioning Expense**
  - APCo: $-$
  - CSPCo: $-$
  - I&M: $(285,265)$

- **Deferred Fuel and Purchased Power**
  - APCo: $(15,559)$
  - CSPCo: $(39)$
  - I&M: $18,708$

- **Deferred Income Taxes on Other Comprehensive Loss**
  - APCo: $18,708$
  - CSPCo: $10,120$
  - I&M: $8,440$

- **Accrued Pensions**
  - APCo: $(21,638)$
  - CSPCo: $(21,930)$
  - I&M: $(13,880)$

- **Nuclear Fuel**
  - APCo: $-$
  - CSPCo: $-$
  - I&M: $(11,862)$

- **Regulatory Assets**
  - APCo: $(69,574)$
  - CSPCo: $(38,231)$
  - I&M: $(25,436)$

- **All Other, Net**
  - APCo: $32,605$
  - CSPCo: $5,819$
  - I&M: $24,231$

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System’s current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2000. The Registrant Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management’s opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.
The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Prior to the adoption of FIN 48, the Registrant Subsidiaries recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48 on January 1, 2007, the Registrant Subsidiaries began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. The impact of this interpretation was an unfavorable (favorable) adjustment to the 2007 opening balance of retained earnings as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>2,685</td>
</tr>
<tr>
<td>CSPCo</td>
<td>3,022</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>(327)</td>
</tr>
<tr>
<td>OPCo</td>
<td>5,380</td>
</tr>
<tr>
<td>PSO</td>
<td>386</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,642</td>
</tr>
</tbody>
</table>

The following table shows the amounts reported for interest expense, interest income and reversal of prior period interest expense.

<table>
<thead>
<tr>
<th>Company</th>
<th>2008</th>
<th></th>
<th>2007</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Expense</td>
<td>Refund</td>
<td>Prior Period</td>
<td>Expense</td>
</tr>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td>Reversal</td>
<td>(in thousands)</td>
</tr>
<tr>
<td>APCo</td>
<td>2,365</td>
<td>5,367</td>
<td>2,635</td>
<td>1,229</td>
</tr>
<tr>
<td>CSPCo</td>
<td>153</td>
<td>3,304</td>
<td>3,411</td>
<td>1,649</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>179</td>
<td>1,371</td>
<td>5,650</td>
<td>1,704</td>
</tr>
<tr>
<td>OPCo</td>
<td>4,093</td>
<td>5,755</td>
<td>295</td>
<td>1,144</td>
</tr>
<tr>
<td>PSO</td>
<td>2,008</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,340</td>
<td>1,585</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

The following table shows the amount accrued for the receipt of interest as of December 31, 2008 and 2007:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008</th>
<th></th>
<th>2007</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td>5,271</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CSPCo</td>
<td>3,905</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2,119</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPCo</td>
<td>4,508</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>1,004</td>
<td>1,371</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,913</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The following table shows the amount accrued for the payment of interest and penalties as of December 31, 2008 and 2007:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008</th>
<th></th>
<th>2007</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td>4,966</td>
<td>6,701</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CSPCo</td>
<td>920</td>
<td>155</td>
<td></td>
<td></td>
</tr>
<tr>
<td>I&amp;M</td>
<td>873</td>
<td>2,162</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPCo</td>
<td>6,320</td>
<td>6,175</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>3,349</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2,658</td>
<td>843</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Balance at January 1, 2008</strong></td>
<td>$19,741</td>
<td>$19,753</td>
<td>$11,317</td>
<td>$51,982</td>
<td>$14,105</td>
<td>$6,610</td>
</tr>
<tr>
<td>Increase - Tax Positions Taken During a Prior Period</td>
<td>1,617</td>
<td>1,198</td>
<td>100</td>
<td>3,133</td>
<td>1,322</td>
<td>2,233</td>
</tr>
<tr>
<td>Decrease - Tax Positions Taken During a Prior Period</td>
<td>(486)</td>
<td>(1,207)</td>
<td>(2,976)</td>
<td>(2,692)</td>
<td>(6,383)</td>
<td>(2,271)</td>
</tr>
<tr>
<td>Increase - Tax Positions Taken During the Current Year</td>
<td>2,891</td>
<td>1,575</td>
<td>3,335</td>
<td>2,446</td>
<td>4,806</td>
<td>4,193</td>
</tr>
<tr>
<td>Decrease - Tax Positions Taken During the Current Year</td>
<td>(1,931)</td>
<td>(311)</td>
<td>(436)</td>
<td>(835)</td>
<td>(540)</td>
<td>(395)</td>
</tr>
<tr>
<td>Increase - Settlements with Taxing Authorities</td>
<td>906</td>
<td>171</td>
<td>745</td>
<td>192</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Decrease - Settlements with Taxing Authorities</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(28)</td>
</tr>
<tr>
<td>Decrease - Lapse of the Applicable Statute of Limitations</td>
<td>(2,165)</td>
<td>-</td>
<td>(270)</td>
<td>(1,888)</td>
<td>-</td>
<td>(90)</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2008</strong></td>
<td>$20,573</td>
<td>$21,179</td>
<td>$11,815</td>
<td>$52,338</td>
<td>$13,310</td>
<td>$10,252</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Company</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Balance at January 1, 2007</strong></td>
<td>$21,729</td>
<td>$24,978</td>
<td>$18,232</td>
<td>$49,839</td>
<td>$8,941</td>
<td>$7,051</td>
</tr>
<tr>
<td>Increase - Tax Positions Taken During a Prior Period</td>
<td>2,074</td>
<td>462</td>
<td>130</td>
<td>2,544</td>
<td>6,535</td>
<td>391</td>
</tr>
<tr>
<td>Decrease - Tax Positions Taken During a Prior Period</td>
<td>(7,323)</td>
<td>(2,494)</td>
<td>(8,455)</td>
<td>(5,248)</td>
<td>(5,526)</td>
<td>(3,425)</td>
</tr>
<tr>
<td>Increase - Tax Positions Taken During the Current Year</td>
<td>3,261</td>
<td>1,491</td>
<td>1,583</td>
<td>6,464</td>
<td>2,018</td>
<td>3,416</td>
</tr>
<tr>
<td>Decrease – Tax Positions Taken During the Current Year</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Increase - Settlements with Taxing Authorities</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2,137</td>
<td>-</td>
</tr>
<tr>
<td>Decrease - Settlements with Taxing Authorities</td>
<td>-</td>
<td>-</td>
<td>(173)</td>
<td>-</td>
<td>-</td>
<td>(193)</td>
</tr>
<tr>
<td>Decrease - Lapse of the Applicable Statute of Limitations</td>
<td>(2,165)</td>
<td>-</td>
<td>(270)</td>
<td>(1,888)</td>
<td>-</td>
<td>(90)</td>
</tr>
<tr>
<td><strong>Balance at December 31, 2007</strong></td>
<td>$19,741</td>
<td>$19,753</td>
<td>$11,317</td>
<td>$51,982</td>
<td>$14,105</td>
<td>$6,610</td>
</tr>
</tbody>
</table>

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant Subsidiary was as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$5,738</td>
</tr>
<tr>
<td>CSPCo</td>
<td>11,954</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>6,283</td>
</tr>
<tr>
<td>OPCo</td>
<td>27,307</td>
</tr>
<tr>
<td>PSO</td>
<td>2,974</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2,205</td>
</tr>
</tbody>
</table>
Federal Tax Legislation – Affecting APCo, CSPCo and OPCo

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was allocated credits during this round of credit awards. After one of the original credit recipients surrendered its credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. AEP filed a new application in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, AEP entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits.

Federal Tax Legislation – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo


The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit for each Registrant Subsidiary as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$38,015</td>
</tr>
<tr>
<td>CSPCo</td>
<td>22,511</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>22,808</td>
</tr>
<tr>
<td>OPCo</td>
<td>26,029</td>
</tr>
<tr>
<td>PSO</td>
<td>12,118</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>58,566</td>
</tr>
</tbody>
</table>

In October 2008, the Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law. The 2008 Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits and energy efficient commercial building deductions. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

In February 2009, the American Recovery and Reinvestment Tax Act of 2009 (the 2009 Act) was signed into law. The 2009 Act extended the bonus depreciation deduction for one year and provides for a long-term extension of the renewable production tax credit for wind energy and other properties. The 2009 Act also establishes a new investment tax credit for the manufacture of advanced energy property as well as appropriations for advanced energy research projects, carbon capture and storage and gridSMART technology. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income or financial condition, but is expected to have a positive material impact on cash flows.
In June 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, AEP reversed deferred state income tax liabilities that are not expected to reverse during the phase-out as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Regulatory Liabilities (a)</th>
<th>SFAS 109 Regulatory Asset, Net (b)</th>
<th>State Income Tax Expense (c)</th>
<th>Deferred State Income Tax Liabilities (d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$</td>
<td>$10,945</td>
<td>$2,769</td>
<td>$13,714</td>
</tr>
<tr>
<td>CSPCo</td>
<td>15,104</td>
<td>-</td>
<td>-</td>
<td>15,104</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>-</td>
<td>5,195</td>
<td>-</td>
<td>5,195</td>
</tr>
<tr>
<td>OPCo</td>
<td>41,864</td>
<td>-</td>
<td>-</td>
<td>41,864</td>
</tr>
<tr>
<td>PSO</td>
<td>-</td>
<td>-</td>
<td>706</td>
<td>706</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>-</td>
<td>582</td>
<td>119</td>
<td>701</td>
</tr>
</tbody>
</table>

(a) The reversal of deferred state income taxes for the Ohio companies was recorded as a regulatory liability pending rate-making treatment in Ohio. See “Ormet” section of Note 4.
(b) Deferred state income tax adjustments related to those companies in which state income taxes flow through for rate-making purposes reduced the regulatory asset associated with the deferred state income tax liabilities.
(c) These amounts were recorded as a reduction to Income Tax Expense.
(d) Total deferred state income tax liabilities that reversed during 2005 related to Ohio law change.

In November 2006, the PUCO ordered OPCo and CSPCo to amortize $42 million and $15 million, respectively, to income as an offset to power supply contract losses incurred by OPCo and CSPCo for sales to Ormet. At December 31, 2008 both regulatory liabilities were fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this new tax, expenses of approximately $4 million, $3 million and $2 million each for CSPCo and OPCo were recorded in 2008, 2007 and 2006, respectively, in Taxes Other than Income Taxes.

State Tax Legislation – Affecting PSO and SWEPCo

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the law reduced Texas income tax rates and was effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109. Based on the new law, management reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 the following adjustments were recorded:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>$</td>
<td>$3,273</td>
<td>$3,273</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>4,438</td>
<td>501</td>
<td>4,939</td>
</tr>
</tbody>
</table>
State Tax Legislation – Affecting APCo, CSPCo, I&M and OPCo

In July 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan’s principal business tax. The new law is effective January 1, 2008 and replaces the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

In September 2007, the Governor of Michigan signed House Bill 5198 which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15 year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. Management has evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect net income, cash flows or financial condition.

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

<table>
<thead>
<tr>
<th>Year Ended December 31</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2008</strong> (in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Lease Expense on Operating Leases</td>
<td>18,840</td>
<td>42,330</td>
<td>96,595</td>
<td>25,876</td>
<td>6,995</td>
<td>8,519</td>
</tr>
<tr>
<td>Amortization of Capital Leases</td>
<td>4,820</td>
<td>3,329</td>
<td>39,697</td>
<td>6,369</td>
<td>1,550</td>
<td>6,926</td>
</tr>
<tr>
<td>Interest on Capital Leases</td>
<td>525</td>
<td>482</td>
<td>5,311</td>
<td>1,606</td>
<td>140</td>
<td>3,855</td>
</tr>
<tr>
<td><strong>Total Lease Rental Costs</strong></td>
<td>24,185</td>
<td>46,141</td>
<td>141,603</td>
<td>33,851</td>
<td>8,685</td>
<td>19,300</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year Ended December 31</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2007</strong> (in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Lease Expense on Operating Leases</td>
<td>14,955</td>
<td>28,316</td>
<td>95,991</td>
<td>23,145</td>
<td>8,176</td>
<td>7,618</td>
</tr>
<tr>
<td>Amortization of Capital Leases</td>
<td>4,498</td>
<td>2,925</td>
<td>6,699</td>
<td>7,526</td>
<td>1,510</td>
<td>8,194</td>
</tr>
<tr>
<td>Interest on Capital Leases</td>
<td>691</td>
<td>609</td>
<td>2,679</td>
<td>2,132</td>
<td>290</td>
<td>6,613</td>
</tr>
<tr>
<td><strong>Total Lease Rental Costs</strong></td>
<td>20,144</td>
<td>31,850</td>
<td>105,369</td>
<td>32,803</td>
<td>9,976</td>
<td>22,425</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year Ended December 31</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2006</strong> (in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Lease Expense on Operating Leases</td>
<td>12,657</td>
<td>5,093</td>
<td>97,750</td>
<td>20,985</td>
<td>6,901</td>
<td>6,808</td>
</tr>
<tr>
<td>Amortization of Capital Leases</td>
<td>5,825</td>
<td>3,221</td>
<td>6,533</td>
<td>7,946</td>
<td>1,155</td>
<td>6,504</td>
</tr>
<tr>
<td>Interest on Capital Leases</td>
<td>873</td>
<td>429</td>
<td>2,807</td>
<td>2,155</td>
<td>232</td>
<td>3,689</td>
</tr>
<tr>
<td><strong>Total Lease Rental Costs</strong></td>
<td>19,355</td>
<td>8,743</td>
<td>107,090</td>
<td>31,086</td>
<td>8,288</td>
<td>17,001</td>
</tr>
</tbody>
</table>
The following table shows the property, plant and equipment under capital leases and related obligations recorded on the Registrant Subsidiaries’ balance sheets. For I&M, current capital lease obligations are included in Obligations Under Capital Leases on I&M’s Consolidated Balance Sheets. For all other Registrant Subsidiaries, current capital lease obligations are included in Current Liabilities – Other. For all Registrant Subsidiaries, long-term capital lease obligations are included in Noncurrent Liabilities – Deferred Credits and Other on the Registrant Subsidiaries’ balance sheets.

<table>
<thead>
<tr>
<th>December 31, 2008</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Property, Plant and Equipment Under Capital Leases:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>$ -</td>
<td>$ 7,104</td>
<td>$ 15,617</td>
<td>$ 21,220</td>
<td>$ -</td>
<td>$ 14,270</td>
</tr>
<tr>
<td>Distribution</td>
<td>-</td>
<td>-</td>
<td>14,589</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>19,651</td>
<td>10,147</td>
<td>81,839</td>
<td>24,748</td>
<td>7,051</td>
<td>156,867</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Property, Plant and Equipment</td>
<td>19,651</td>
<td>17,251</td>
<td>112,045</td>
<td>45,968</td>
<td>7,051</td>
<td>171,137</td>
</tr>
<tr>
<td>Accumulated Amortization</td>
<td>10,338</td>
<td>10,410</td>
<td>30,643</td>
<td>21,490</td>
<td>3,573</td>
<td>59,249</td>
</tr>
<tr>
<td><strong>Net Property, Plant and Equipment Under Capital Leases</strong></td>
<td>$ 9,313</td>
<td>$ 6,841</td>
<td>$ 81,402</td>
<td>$ 24,478</td>
<td>$ 3,478</td>
<td>$ 111,888</td>
</tr>
<tr>
<td><strong>Obligations Under Capital Leases:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noncurrent Liability</td>
<td>$ 5,551</td>
<td>$ 4,055</td>
<td>$ 37,890</td>
<td>$ 19,603</td>
<td>$ 2,082</td>
<td>$ 99,151</td>
</tr>
<tr>
<td>Liability Due Within One Year</td>
<td>3,762</td>
<td>2,804</td>
<td>43,512</td>
<td>6,863</td>
<td>1,396</td>
<td>13,574</td>
</tr>
<tr>
<td><strong>Total Obligations Under Capital Leases</strong></td>
<td>$ 9,313</td>
<td>$ 6,859</td>
<td>$ 81,402</td>
<td>$ 26,466</td>
<td>$ 3,478</td>
<td>$ 112,725</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>December 31, 2007</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Property, Plant and Equipment Under Capital Leases:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>$ -</td>
<td>$ 7,104</td>
<td>$ 15,643</td>
<td>$ 39,484</td>
<td>$ -</td>
<td>$ 14,270</td>
</tr>
<tr>
<td>Distribution</td>
<td>-</td>
<td>-</td>
<td>14,589</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>28,234</td>
<td>12,686</td>
<td>117,249</td>
<td>27,670</td>
<td>6,576</td>
<td>95,442</td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Property, Plant and Equipment</td>
<td>28,234</td>
<td>19,790</td>
<td>147,481</td>
<td>67,154</td>
<td>6,576</td>
<td>148,863</td>
</tr>
<tr>
<td>Accumulated Amortization</td>
<td>17,133</td>
<td>11,681</td>
<td>26,922</td>
<td>39,809</td>
<td>2,548</td>
<td>49,243</td>
</tr>
<tr>
<td><strong>Net Property, Plant and Equipment Under Capital Leases</strong></td>
<td>$ 11,101</td>
<td>$ 8,109</td>
<td>$ 120,559</td>
<td>$ 27,345</td>
<td>$ 4,028</td>
<td>$ 99,620</td>
</tr>
<tr>
<td><strong>Obligations Under Capital Leases:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noncurrent Liability</td>
<td>$ 6,280</td>
<td>$ 4,885</td>
<td>$ 77,177</td>
<td>$ 21,062</td>
<td>$ 2,527</td>
<td>$ 89,765</td>
</tr>
<tr>
<td>Liability Due Within One Year</td>
<td>4,821</td>
<td>3,243</td>
<td>43,382</td>
<td>8,015</td>
<td>1,501</td>
<td>10,555</td>
</tr>
<tr>
<td><strong>Total Obligations Under Capital Leases</strong></td>
<td>$ 11,101</td>
<td>$ 8,128</td>
<td>$ 120,559</td>
<td>$ 29,077</td>
<td>$ 4,028</td>
<td>$ 100,320</td>
</tr>
</tbody>
</table>
Future minimum lease payments consisted of the following at December 31, 2008:

<table>
<thead>
<tr>
<th>Capital Leases</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$3,888</td>
<td>$2,929</td>
<td>$31,351</td>
<td>$6,062</td>
<td>$1,451</td>
<td>$17,892</td>
</tr>
<tr>
<td>2010</td>
<td>3,153</td>
<td>2,367</td>
<td>22,295</td>
<td>4,974</td>
<td>982</td>
<td>13,734</td>
</tr>
<tr>
<td>2011</td>
<td>1,975</td>
<td>1,280</td>
<td>7,113</td>
<td>3,692</td>
<td>775</td>
<td>22,301</td>
</tr>
<tr>
<td>2012</td>
<td>121</td>
<td>92</td>
<td>10,575</td>
<td>1,793</td>
<td>69</td>
<td>9,100</td>
</tr>
<tr>
<td>2013</td>
<td>121</td>
<td>92</td>
<td>4,800</td>
<td>2,333</td>
<td>69</td>
<td>9,008</td>
</tr>
<tr>
<td>Later Years</td>
<td>401</td>
<td>362</td>
<td>24,486</td>
<td>17,608</td>
<td>282</td>
<td>75,000</td>
</tr>
<tr>
<td>Total Future Minimum Lease Payments</td>
<td>9,659</td>
<td>7,122</td>
<td>100,620</td>
<td>36,462</td>
<td>3,628</td>
<td>147,035</td>
</tr>
<tr>
<td>Less Estimated Interest Element</td>
<td>346</td>
<td>263</td>
<td>19,218</td>
<td>9,996</td>
<td>150</td>
<td>34,310</td>
</tr>
<tr>
<td>Estimated Present Value of Future Minimum Lease Payments</td>
<td>$9,313</td>
<td>$6,859</td>
<td>$81,402</td>
<td>$26,466</td>
<td>$3,478</td>
<td>$112,725</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Noncancelable Operating Leases</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$20,592</td>
<td>$45,091</td>
<td>$100,181</td>
<td>$26,707</td>
<td>$5,646</td>
<td>$8,554</td>
</tr>
<tr>
<td>2010</td>
<td>19,233</td>
<td>39,246</td>
<td>96,596</td>
<td>24,961</td>
<td>5,192</td>
<td>6,444</td>
</tr>
<tr>
<td>2011</td>
<td>43,830</td>
<td>51,272</td>
<td>119,252</td>
<td>54,111</td>
<td>17,424</td>
<td>30,672</td>
</tr>
<tr>
<td>2012</td>
<td>7,777</td>
<td>33,190</td>
<td>88,878</td>
<td>15,096</td>
<td>351</td>
<td>1,835</td>
</tr>
<tr>
<td>2013</td>
<td>7,347</td>
<td>32,332</td>
<td>87,474</td>
<td>15,031</td>
<td>259</td>
<td>1,643</td>
</tr>
<tr>
<td>Later Years</td>
<td>61,236</td>
<td>121,100</td>
<td>709,434</td>
<td>74,915</td>
<td>564</td>
<td>15,233</td>
</tr>
<tr>
<td>Total Future Minimum Lease Payments</td>
<td>$160,015</td>
<td>$322,231</td>
<td>$1,201,815</td>
<td>$210,821</td>
<td>$29,436</td>
<td>$64,381</td>
</tr>
</tbody>
</table>

**Master Lease Agreements**

Certain Registrant Subsidiaries lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2010 and 2011, the Registrant Subsidiaries will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the following unamortized values for this equipment is reflected in the Registrant Subsidiaries’ future minimum lease payments for 2011:

<table>
<thead>
<tr>
<th>Company</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$29,461</td>
</tr>
<tr>
<td>CSPCo</td>
<td>14,916</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>25,422</td>
</tr>
<tr>
<td>OPCo</td>
<td>31,832</td>
</tr>
<tr>
<td>PSO</td>
<td>14,095</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>25,462</td>
</tr>
</tbody>
</table>

In addition, an immaterial amount for the unamortized value of the equipment is included in the Registrant Subsidiaries’ future minimum lease payments for 2010. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into additional replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2010 and 2011.
For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At December 31, 2008, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Maximum Potential Loss (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$2,634</td>
</tr>
<tr>
<td>CSPCo</td>
<td>885</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>1,383</td>
</tr>
<tr>
<td>OPCo</td>
<td>2,300</td>
</tr>
<tr>
<td>PSO</td>
<td>1,643</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,277</td>
</tr>
</tbody>
</table>

**Rockport Lease**

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction for each respective company as of December 31, 2008 are as follows:

<table>
<thead>
<tr>
<th>Future Minimum Lease Payments</th>
<th>AEGCo (in millions)</th>
<th>I&amp;M (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$74</td>
<td>$74</td>
</tr>
<tr>
<td>2010</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>2011</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>2012</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>2013</td>
<td>74</td>
<td>74</td>
</tr>
<tr>
<td>Later Years</td>
<td>665</td>
<td>665</td>
</tr>
<tr>
<td>Total Future Minimum Lease Payments</td>
<td>$1,035</td>
<td>$1,035</td>
</tr>
</tbody>
</table>

**Railcar Lease**

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as new operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of December 31, 2008. These obligations are included in I&M’s and SWEPCo’s future minimum lease payments schedule earlier in this note.
Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20 year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M’s maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo’s is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair market value would produce a sufficient sales price to avoid any loss.

The Registrant Subsidiaries have other railcar lease arrangements that do not utilize this type of financing structure.

**Sabine Dragline Lease**

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46R, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a $53 million electric dragline for Sabine’s mining operations. In 2006, the initial capital outlay for the dragline was $26 million. Sabine incurred an additional $14 million and $13 million of transportation, assembly and upgrade costs in 2008 and 2007, respectively. The dragline was completed in August 2008. For the years ended December 31, 2008 and 2007, Sabine paid $1 million and $2 million, respectively, of interim rent prior to the completion in August 2008. Sabine began quarterly principal and interest payments on the outstanding lease obligation in November 2008. The capital lease asset was included in Property, Plant and Equipment – Other and Construction Work in Progress on SWEPCo’s December 31, 2008 and 2007 Consolidated Balance Sheets, respectively. The short-term and long-term capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on SWEPCo’s December 31, 2008 and 2007 Consolidated Balance Sheets. The future payment obligations are included in SWEPCo’s future minimum lease payments schedule earlier in this note.

**I&M Nuclear Fuel Lease**

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M’s Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $57 million are included in I&M’s future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Property, Plant and Equipment – Other and the short-term and long-term capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other, respectively, on I&M’s December 31, 2008 and 2007 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2008 are as follows, based on estimated fuel burn:

<table>
<thead>
<tr>
<th>Future Minimum Lease Payments</th>
<th>(in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$25</td>
</tr>
<tr>
<td>2010</td>
<td>18</td>
</tr>
<tr>
<td>2011</td>
<td>4</td>
</tr>
<tr>
<td>2012</td>
<td>7</td>
</tr>
<tr>
<td>2013</td>
<td>3</td>
</tr>
<tr>
<td>Later Years</td>
<td>-</td>
</tr>
<tr>
<td>Total Future Minimum Lease Payments</td>
<td>$57</td>
</tr>
</tbody>
</table>
14. **FINANCING ACTIVITIES**

**Preferred Stock**

<table>
<thead>
<tr>
<th>Company</th>
<th>Par Value</th>
<th>Authorized Shares</th>
<th>Shares Outstanding at December 31, 2008</th>
<th>Call Price at December 31, 2008 (a)</th>
<th>Series</th>
<th>Redemption</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$ 0 (b)</td>
<td>8,000,000</td>
<td>177,520</td>
<td>110.00</td>
<td>4.50%</td>
<td>Any time</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$ 17,752</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$ 17,752</td>
</tr>
<tr>
<td>CSPCo</td>
<td>25</td>
<td>7,000,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CSPCo</td>
<td>100</td>
<td>2,500,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>25</td>
<td>11,200,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>100 (c)</td>
<td>55,335</td>
<td>106.13</td>
<td>4.125%</td>
<td>Any time</td>
<td>5,533</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>100 (c)</td>
<td>14,412</td>
<td>102.00</td>
<td>4.56%</td>
<td>Any time</td>
<td>1,441</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>100 (c)</td>
<td>11,055</td>
<td>102.73</td>
<td>4.12%</td>
<td>Any time</td>
<td>1,106</td>
</tr>
<tr>
<td>OPCo</td>
<td>25</td>
<td>4,000,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>OPCo</td>
<td>100 (d)</td>
<td>14,595</td>
<td>103.00</td>
<td>4.08%</td>
<td>Any time</td>
<td>1,460</td>
</tr>
<tr>
<td>OPCo</td>
<td>100 (d)</td>
<td>22,824</td>
<td>103.20</td>
<td>4.20%</td>
<td>Any time</td>
<td>2,282</td>
</tr>
<tr>
<td>OPCo</td>
<td>100 (d)</td>
<td>31,482</td>
<td>104.00</td>
<td>4.40%</td>
<td>Any time</td>
<td>3,148</td>
</tr>
<tr>
<td>OPCo</td>
<td>100 (d)</td>
<td>97,373</td>
<td>110.00</td>
<td>4.50%</td>
<td>Any time</td>
<td>9,737</td>
</tr>
<tr>
<td>PSO</td>
<td>100 (e)</td>
<td>44,548</td>
<td>105.75</td>
<td>4.00%</td>
<td>Any time</td>
<td>4,455</td>
</tr>
<tr>
<td>PSO</td>
<td>100 (e)</td>
<td>8,069</td>
<td>103.19</td>
<td>4.24%</td>
<td>Any time</td>
<td>807</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>100 (f)</td>
<td>7,386</td>
<td>103.90</td>
<td>4.28%</td>
<td>Any time</td>
<td>740</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>100 (f)</td>
<td>1,907</td>
<td>102.75</td>
<td>4.65%</td>
<td>Any time</td>
<td>190</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>100 (f)</td>
<td>37,673</td>
<td>109.00</td>
<td>5.00%</td>
<td>Any time</td>
<td>3,767</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Stated value is $100 per share.
(c) I&M has 2,250,000 authorized $100 par value per share shares in total.
(d) OPCo has 3,762,403 authorized $100 par value per share shares in total.
(e) PSO has 700,000 authorized shares in total.
(f) SWEPCo has 1,860,000 authorized shares in total.

**Number of Shares Redeemed for the Years Ended December 31, 2008, 2007, 2006**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>4.50%</td>
<td>-</td>
<td>114</td>
<td>202</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>4.12%</td>
<td>-</td>
<td>22</td>
<td>12</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>5.90%</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>6.25%</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>6.30%</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>6.875%</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>OPCo</td>
<td>4.50%</td>
<td>-</td>
<td>-</td>
<td>89</td>
</tr>
<tr>
<td>OPCo</td>
<td>5.90%</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>OPCo</td>
<td>4.40%</td>
<td>-</td>
<td>30</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>5.00%</td>
<td>-</td>
<td>-</td>
<td>30</td>
</tr>
</tbody>
</table>
**Long-term Debt**

There are certain limitations on establishing liens against the Registrant Subsidiaries’ assets under their respective indentures. None of the long-term debt obligations of the Registrant Subsidiaries have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2008 and 2007:

<table>
<thead>
<tr>
<th>Company</th>
<th>Maturity</th>
<th>Weighted Average Interest Rate at December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2008</td>
<td>4.40%-7.00%</td>
<td>3.60%-6.70%</td>
</tr>
<tr>
<td>APCo</td>
<td>2008-2038</td>
<td>5.96%</td>
<td>4.40%-6.60%</td>
<td>4.40%-6.60%</td>
</tr>
<tr>
<td>CSPCo</td>
<td>2008-2035</td>
<td>5.81%</td>
<td>5.05%-6.375%</td>
<td>5.05%-6.45%</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2008-2037</td>
<td>5.54%</td>
<td>4.3875%-6.60%</td>
<td>4.85%-6.60%</td>
</tr>
<tr>
<td>OPCo</td>
<td>2008-2033</td>
<td>5.4%</td>
<td>4.70%-6.625%</td>
<td>4.70%-6.625%</td>
</tr>
<tr>
<td>PSO</td>
<td>2009-2037</td>
<td>5.82%</td>
<td>4.90%-6.45%</td>
<td>4.90%-5.875%</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2015-2019</td>
<td>5.84%</td>
<td>4.90%-6.45%</td>
<td>4.90%-5.875%</td>
</tr>
</tbody>
</table>

**Pollution Control Bonds (a)**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maturity</th>
<th>Weighted Average Interest Rate at December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>2010-2037 (b)</td>
<td>4.26%</td>
<td>1.05%-7.125%</td>
<td>4.40%-6.05%</td>
</tr>
<tr>
<td>CSPCo</td>
<td>2012-2042 (b)</td>
<td>4.99%</td>
<td>4.85%-5.10%</td>
<td>3.90%-4.95%</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2008-2025</td>
<td>3.06%</td>
<td>0.75%-5.25%</td>
<td>4.10%-5.00%</td>
</tr>
<tr>
<td>OPCo</td>
<td>2010-2037 (b)</td>
<td>5.4%</td>
<td>0.85%-13.00%</td>
<td>3.75%-5.80%</td>
</tr>
<tr>
<td>PSO</td>
<td>2014-2020</td>
<td>4.45%</td>
<td>4.45%</td>
<td>4.75%-4.45%</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2011-2019</td>
<td>3.96%</td>
<td>2.034%-4.95%</td>
<td>4.25%-4.50%</td>
</tr>
</tbody>
</table>

**Notes Payable – Affiliated**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maturity</th>
<th>Weighted Average Interest Rate at December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>2010</td>
<td>4.708%</td>
<td>4.708%</td>
<td>4.708%</td>
</tr>
<tr>
<td>CSPCo</td>
<td>2010</td>
<td>4.64%</td>
<td>4.64%</td>
<td>4.64%</td>
</tr>
<tr>
<td>OPCo</td>
<td>2015</td>
<td>5.25%</td>
<td>5.25%</td>
<td>5.25%</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2010</td>
<td>4.45%</td>
<td>4.45%</td>
<td>4.45%</td>
</tr>
</tbody>
</table>

**Notes Payable – Nonaffiliated**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maturity</th>
<th>Weighted Average Interest Rate at December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPCo</td>
<td>2008-2009</td>
<td>7.45%</td>
<td>6.27%-7.49%</td>
<td>6.27%-7.49%</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2008-2024</td>
<td>6.26%</td>
<td>4.47%-7.03%</td>
<td>4.47%-7.03%</td>
</tr>
</tbody>
</table>

**Notes Payable to Trust**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maturity</th>
<th>Weighted Average Interest Rate at December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SWEPCo</td>
<td>2043</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

**Spent Nuclear Fuel Liability (c)**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maturity</th>
<th>Weighted Average Interest Rate at December 31, 2008</th>
<th>Interest Rate Ranges at December 31, 2008</th>
<th>Outstanding at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I&amp;M</td>
<td>2026</td>
<td>13.718%</td>
<td>13.718%</td>
<td>13.718%</td>
</tr>
</tbody>
</table>

(a) Under the terms of the pollution control bonds, each Registrant Subsidiary is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Interest payments range from monthly to semi-annually. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.

(c) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets of $301 million and $285 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts on its Consolidated Balance Sheets at December 31, 2008 and 2007, respectively.
At December 31, 2008 future annual long-term debt payments are as follows:

<table>
<thead>
<tr>
<th></th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$ 150,017</td>
<td>-</td>
<td>$ -</td>
<td>$ 77,500</td>
<td>$ 50,000</td>
<td>$ 4,406</td>
</tr>
<tr>
<td>2010</td>
<td>300,019</td>
<td>250,000</td>
<td>-</td>
<td>679,450</td>
<td>150,000</td>
<td>54,006</td>
</tr>
<tr>
<td>2011</td>
<td>250,022</td>
<td>-</td>
<td>100,000</td>
<td>-</td>
<td>75,000</td>
<td>42,604</td>
</tr>
<tr>
<td>2012</td>
<td>250,025</td>
<td>44,500</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>20,000</td>
</tr>
<tr>
<td>2013</td>
<td>70,028</td>
<td>306,000</td>
<td>-</td>
<td>500,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>After 2013</td>
<td>2,177,130</td>
<td>850,000</td>
<td>1,281,183</td>
<td>1,787,130</td>
<td>612,660</td>
<td>1,360,199</td>
</tr>
<tr>
<td>Total Principal Amount</td>
<td>3,197,241</td>
<td>1,450,500</td>
<td>1,381,183</td>
<td>3,044,080</td>
<td>887,660</td>
<td>1,481,615</td>
</tr>
<tr>
<td>Unamortized Discount</td>
<td>(22,729)</td>
<td>(6,906)</td>
<td>(3,269)</td>
<td>(4,704)</td>
<td>(2,801)</td>
<td>(3,466)</td>
</tr>
<tr>
<td>Total</td>
<td>$ 3,174,512</td>
<td>$ 1,443,594</td>
<td>$ 1,377,914</td>
<td>$ 3,039,376</td>
<td>$ 884,859</td>
<td>$ 1,478,149</td>
</tr>
</tbody>
</table>

In January 2009, I&M issued $475 million of 7.00% Senior Unsecured Notes due in 2019.

In January 2009, AEP Parent loaned I&M $25 million of 5.375% Notes Payable due in 2010.

In February 2009, PSO reissued $33.7 million of 5.25% Pollution Control Bonds due in 2014.

In the first quarter of 2008, bond insurers’ exposure in connection with developments in the subprime credit market resulted in increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates. Consequently, the Registrant Subsidiaries chose to exit the auction-rate debt market and reduced auction-rate securities from the December 2007 balance by $1.1 billion. As of December 31, 2008, OPCo had $218 million of tax-exempt long-term debt sold at auction rates (rates range between 6.388% and 13%) that reset every 35 days. OPCo’s debt relates to a lease structure with JMG that OPCo is unable to refinance without their consent. The initial term for the JMG lease structure matures on March 31, 2010 and management is evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO. As of December 31, 2008, SWEPCo had $53.5 million of tax-exempt long-term debt sold at auction rates (rate of 2.034%) that reset every 35 days. The instruments under which the bonds are issued allow for conversion to other short-term variable-rate structures, term-put structures and fixed-rate structures.

The following table shows the current status of debt as of December 31, 2008 which was issued as auction-rate debt at December 31, 2007:

<table>
<thead>
<tr>
<th>Company</th>
<th>Retired in 2008 (in thousands)</th>
<th>Remarked at Fixed Rates During 2008</th>
<th>Fixed Rate at December 31, 2008 (in thousands)</th>
<th>Remarked at Variable Rates During 2008</th>
<th>Variable Rate at December 31, 2008 (in thousands)</th>
<th>Remains at Auction Rate at December 31, 2008 (in thousands)</th>
<th>Held by Trustee at December 31, 2008 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$</td>
<td>$</td>
<td>$</td>
<td>75,000</td>
<td>0.90%</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td>APCo</td>
<td>-</td>
<td>4,85%</td>
<td>50,275</td>
<td>25,075</td>
<td>1.52%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CSPCo</td>
<td>-</td>
<td>4,85%</td>
<td>-</td>
<td>52,000</td>
<td>0.75%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CSPCo</td>
<td>-</td>
<td>4,85%</td>
<td>-</td>
<td>52,000</td>
<td>0.75%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>45,000</td>
<td>-</td>
<td>5.25%</td>
<td>52,000</td>
<td>0.75%</td>
<td>-</td>
<td>100,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>-</td>
<td>-</td>
<td>25,000</td>
<td>25,000</td>
<td>0.90%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>OPCo</td>
<td>-</td>
<td>-</td>
<td>65,000</td>
<td>65,000</td>
<td>0.65%</td>
<td>-</td>
<td>218,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>-</td>
<td>-</td>
<td>50,000</td>
<td>50,000</td>
<td>0.75%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>OPCo</td>
<td>-</td>
<td>-</td>
<td>50,000</td>
<td>50,000</td>
<td>1.00%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>PSO</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>-</td>
<td>81,700</td>
<td>4.95%</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>33,700</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>-</td>
<td>41,135</td>
<td>4.50%</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td>$ 45,000</td>
<td>$ 333,335</td>
<td>$ 367,275</td>
<td>$ 271,500</td>
<td>$ 328,445</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

**Dividend Restrictions**

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.
Trust Preferred Securities

SWEPCo had a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46R. The SWEPCo trust, which held mandatorily redeemable trust preferred securities, is reported as two components on the Consolidated Balance Sheets. The investment in the trust, which was $3 million as of December 31, 2007, is reported as Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of $113 million as of December 31, 2007, are reported as Notes Payable to Trust within Long-term Debt – Nonaffiliated. Both the investment in the trust and the Junior Subordinated Debentures were retired in 2008.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2008 and 2007 are included in Advances to/from Affiliates on each of the Registrant Subsidiaries’ balance sheets. The Utility Money Pool participants’ money pool activity and their corresponding authorized borrowing limits for the years ended December 31, 2008 and 2007 are described in the following tables:

**Year Ended December 31, 2008:**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maximum Borrowings from Utility Money Pool</th>
<th>Maximum Loans to Utility Money Pool</th>
<th>Average Borrowings from Utility Money Pool</th>
<th>Average Loans to Utility Money Pool</th>
<th>Loans (Borrowings) to/from Utility Money Pool as of December 31, 2008</th>
<th>Authorized Short-Term Borrowing Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$307,226</td>
<td>$269,987</td>
<td>$187,455</td>
<td>$187,192</td>
<td>$ (194,888)</td>
<td>$600,000</td>
</tr>
<tr>
<td>CSPCo</td>
<td>238,172</td>
<td>150,358</td>
<td>132,219</td>
<td>49,899</td>
<td>(74,865)</td>
<td>350,000</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>479,661</td>
<td>-</td>
<td>232,649</td>
<td>-</td>
<td>(476,036)</td>
<td>500,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>415,951</td>
<td>82,486</td>
<td>160,127</td>
<td>28,573</td>
<td>(133,887)</td>
<td>600,000</td>
</tr>
<tr>
<td>PSO</td>
<td>149,278</td>
<td>59,384</td>
<td>69,603</td>
<td>29,811</td>
<td>(70,308)</td>
<td>300,000</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>168,495</td>
<td>300,525</td>
<td>78,074</td>
<td>155,598</td>
<td>(2,526)</td>
<td>350,000</td>
</tr>
</tbody>
</table>

**Year Ended December 31, 2007:**

<table>
<thead>
<tr>
<th>Company</th>
<th>Maximum Borrowings from Utility Money Pool</th>
<th>Maximum Loans to Utility Money Pool</th>
<th>Average Borrowings from Utility Money Pool</th>
<th>Average Loans to Utility Money Pool</th>
<th>Loans (Borrowings) to/from Utility Money Pool as of December 31, 2007</th>
<th>Authorized Short-Term Borrowing Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$406,262</td>
<td>$96,543</td>
<td>$162,526</td>
<td>$36,795</td>
<td>(275,257)</td>
<td>$600,000</td>
</tr>
<tr>
<td>CSPCo</td>
<td>137,696</td>
<td>35,270</td>
<td>57,516</td>
<td>13,511</td>
<td>(95,199)</td>
<td>350,000</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>118,570</td>
<td>52,748</td>
<td>48,033</td>
<td>30,277</td>
<td>(45,064)</td>
<td>500,000</td>
</tr>
<tr>
<td>OPCo</td>
<td>447,335</td>
<td>1,564</td>
<td>144,776</td>
<td>1,564</td>
<td>(101,548)</td>
<td>600,000</td>
</tr>
<tr>
<td>PSO</td>
<td>242,097</td>
<td>176,077</td>
<td>131,975</td>
<td>125,469</td>
<td>51,202</td>
<td>300,000</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>245,278</td>
<td>97,328</td>
<td>108,820</td>
<td>31,341</td>
<td>(1,565)</td>
<td>350,000</td>
</tr>
</tbody>
</table>
The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

<table>
<thead>
<tr>
<th></th>
<th>Years Ended December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
<td>2006</td>
</tr>
<tr>
<td>Maximum Interest Rate</td>
<td>5.47%</td>
<td>5.94%</td>
<td>5.41%</td>
</tr>
<tr>
<td>Minimum Interest Rate</td>
<td>2.28%</td>
<td>5.16%</td>
<td>3.32%</td>
</tr>
</tbody>
</table>

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2008, 2007 and 2006 are summarized for all Registrant Subsidiaries in the following table:

<table>
<thead>
<tr>
<th>Company</th>
<th>Average Interest Rate for Funds Borrowed from the Utility Money Pool for Years Ended December 31,</th>
<th>Average Interest Rate for Funds Loaned to the Utility Money Pool for Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>3.66%</td>
<td>5.38%</td>
</tr>
<tr>
<td>CSPCo</td>
<td>3.59%</td>
<td>5.46%</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>3.35%</td>
<td>5.37%</td>
</tr>
<tr>
<td>OPCo</td>
<td>3.24%</td>
<td>5.39%</td>
</tr>
<tr>
<td>PSO</td>
<td>3.32%</td>
<td>5.48%</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>3.38%</td>
<td>5.47%</td>
</tr>
</tbody>
</table>

Interest expense related to the Utility Money Pool is included in Interest Expense in each of the Registrant Subsidiaries’ Financial Statements. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31,</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td>APCo</td>
<td>$ 6,076</td>
<td>$ 6,897</td>
</tr>
<tr>
<td>CSPCo</td>
<td>2,287</td>
<td>2,561</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>7,903</td>
<td>2,399</td>
</tr>
<tr>
<td>OPCo</td>
<td>4,912</td>
<td>7,958</td>
</tr>
<tr>
<td>PSO</td>
<td>1,856</td>
<td>6,398</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,480</td>
<td>4,414</td>
</tr>
</tbody>
</table>

Interest income related to the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries’ Financial Statements. The Registrant Subsidiaries earned interest income for amounts advanced to the Utility Money Pool as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31,</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
</tr>
<tr>
<td>APCo</td>
<td>$ 872</td>
<td>$ 470</td>
</tr>
<tr>
<td>CSPCo</td>
<td>880</td>
<td>142</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>-</td>
<td>171</td>
</tr>
<tr>
<td>OPCo</td>
<td>79</td>
<td>-</td>
</tr>
<tr>
<td>PSO</td>
<td>293</td>
<td>881</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>2,540</td>
<td>542</td>
</tr>
</tbody>
</table>
**Short-term Debt**

The Registrant Subsidiaries’ outstanding short-term debt was as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Type of Debt</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Outstanding Amount</td>
<td>Interest Rate (a)</td>
<td>Outstanding Amount</td>
</tr>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td>(in thousands)</td>
</tr>
<tr>
<td>OPCo</td>
<td>Commercial Paper – JMG(b)</td>
<td>$ -</td>
<td>-%</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Line of Credit – Sabine (c)</td>
<td>7,172</td>
<td>1.54%</td>
</tr>
</tbody>
</table>

(a) Weighted average rate.
(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce OPCo’s available liquidity.
(c) Sabine Mining Company is consolidated under FIN 46R.

**Credit Facilities**

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of December 31, 2008, $372 million of letters of credit were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds as follows:

**Letters of Credit Amount Outstanding Against $650 million 3-year Agreement**

<table>
<thead>
<tr>
<th>Company</th>
<th>Amount (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>126.7</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>77.9</td>
</tr>
<tr>
<td>OPCo</td>
<td>166.9</td>
</tr>
</tbody>
</table>

**Sale of Receivables – AEP Credit**

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities,” allowing the receivables to be taken off of AEP Credit’s balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies’ receivables, and accelerate AEP Credit’s cash collections.

In October 2008, AEP renewed AEP Credit’s sale of receivables agreement. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009. AEP intends to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in October 2008 and was extended until October 2009, provided a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the previous sale of receivable agreement, the commitment increased to $700 million for the months of August and September to accommodate seasonal demand. At December 31, 2008, $650 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.
AEP Credit purchases accounts receivable through purchase agreements with CSPCo, I&M, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo’s accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>(in millions)</td>
</tr>
<tr>
<td>Proceeds from Sale of Accounts Receivable</td>
</tr>
<tr>
<td>Loss on Sale of Accounts Receivable</td>
</tr>
<tr>
<td>Average Variable Discount Rate</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Accounts Receivable Retained Interest and Pledged as Collateral</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 31,</td>
</tr>
<tr>
<td>2008</td>
</tr>
<tr>
<td>(in millions)</td>
</tr>
<tr>
<td>Accounts Receivable Retained Interest and Pledged as Collateral</td>
</tr>
<tr>
<td>Less Uncollectible Accounts</td>
</tr>
<tr>
<td>Deferred Revenue from Servicing Accounts Receivable</td>
</tr>
<tr>
<td>Retained Interest if 10% Adverse Change in Uncollectible Accounts</td>
</tr>
<tr>
<td>Retained Interest if 20% Adverse Change in Uncollectible Accounts</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>December 31,</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
</tr>
<tr>
<td>(in millions)</td>
</tr>
<tr>
<td>Customer Accounts Receivable Retained</td>
</tr>
<tr>
<td>Accrued Unbilled Revenues Retained</td>
</tr>
<tr>
<td>Miscellaneous Accounts Receivable Retained</td>
</tr>
<tr>
<td>Allowance for Uncollectible Accounts Retained</td>
</tr>
<tr>
<td>Total Net Balance Sheet Accounts Receivable</td>
</tr>
<tr>
<td>Customer Accounts Receivable Securitized</td>
</tr>
<tr>
<td>Total Accounts Receivable Managed</td>
</tr>
</tbody>
</table>

Customer accounts receivable retained and securitized for the electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $22 million and $30 million at December 31, 2008 and 2007, respectively. AEP Credit’s delinquent customer accounts receivable represents accounts greater than 30 days past due.

Under the factoring arrangement, participating Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company’s receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the participant’s statement of operations.
The amount of factored accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>December 31, 2008 (in millions)</th>
<th>December 31, 2007 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$131.1</td>
<td>$83.8</td>
</tr>
<tr>
<td>CSPCo</td>
<td>144.9</td>
<td>133.1</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>110.2</td>
<td>101.0</td>
</tr>
<tr>
<td>OPCo</td>
<td>138.1</td>
<td>118.5</td>
</tr>
<tr>
<td>PSO</td>
<td>135.9</td>
<td>109.3</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>105.3</td>
<td>94.3</td>
</tr>
</tbody>
</table>

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31, 2008 (in millions)</th>
<th>Years Ended December 31, 2007 (in millions)</th>
<th>Years Ended December 31, 2006 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$6.1</td>
<td>$6.9</td>
<td>$6.3</td>
</tr>
<tr>
<td>CSPCo</td>
<td>12.7</td>
<td>15.2</td>
<td>13.7</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>7.2</td>
<td>9.3</td>
<td>9.2</td>
</tr>
<tr>
<td>OPCo</td>
<td>10.0</td>
<td>12.6</td>
<td>11.1</td>
</tr>
<tr>
<td>PSO</td>
<td>10.9</td>
<td>14.1</td>
<td>16.3</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>8.0</td>
<td>10.7</td>
<td>10.5</td>
</tr>
</tbody>
</table>

15. RELATED PARTY TRANSACTIONS

For other related party transactions, also see “Utility Money Pool – AEP System” and “Sale of Receivables – AEP Credit” sections of Note 14.

AEP Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company’s MLR, which is calculated monthly on the basis of each company’s maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by AEPSC and profits/losses are allocated under the SIA to AEP Power Pool members, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC options and swaps. The majority of these transactions represent physical forward contracts in the AEP System’s traditional marketing area and are typically settled by entering into offsetting contracts. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System’s traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. In February 2006, AEP filed with the FERC a proposed amendment to the CSW Operating Agreement to remove TCC and TNC as parties to the agreement. Pursuant to Texas electric restructuring law, those companies exited the generation and load-servicing businesses. AEP made a similar filing to remove those two companies as parties to the SIA. The filings were approved effective May 1, 2006 and April 1, 2006, respectively.
The CSW Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer’s incremental cost plus a portion of the recipient’s savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

**System Integration Agreement (SIA)**

The SIA provides for the integration and coordination of AEP East companies and AEP West companies' zones. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any Registrant Subsidiary is primarily sold to customers by such Registrant Subsidiary at rates approved (other than in Ohio) by the public utility commission in the jurisdiction of sale. In Ohio, such rates are based on a statutory formula as those jurisdictions transition to the use of market rates for generation (see Note 4).

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

**Affiliated Revenues and Purchases**

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Related Party Revenues</th>
<th>APCo (in thousands)</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales to AEP Power Pool</td>
<td>$ 219,305</td>
<td>$ 101,743</td>
<td>$ 292,183</td>
<td>$ 849,574</td>
<td>$ N/A</td>
<td>$ N/A</td>
</tr>
<tr>
<td>Direct Sales to East Affiliates</td>
<td>92,225</td>
<td>-</td>
<td>-</td>
<td>74,465</td>
<td>4,246</td>
<td>3,438</td>
</tr>
<tr>
<td>Direct Sales to West Affiliates</td>
<td>16,558</td>
<td>9,489</td>
<td>9,483</td>
<td>11,505</td>
<td>90,545</td>
<td>33,493</td>
</tr>
<tr>
<td>Natural Gas Contracts with AEPES</td>
<td>(2,029)</td>
<td>(1,203)</td>
<td>(1,085)</td>
<td>(689)</td>
<td>(467)</td>
<td>(552)</td>
</tr>
<tr>
<td>Other</td>
<td>2,676</td>
<td>12,560</td>
<td>2,160</td>
<td>5,613</td>
<td>7,278</td>
<td>14,463</td>
</tr>
<tr>
<td><strong>Total Revenues</strong></td>
<td>$ 328,735</td>
<td>$ 122,949</td>
<td>$ 302,741</td>
<td>$ 940,468</td>
<td>$ 101,602</td>
<td>$ 50,842</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Related Party Revenues</th>
<th>APCo (in thousands)</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year Ended December 31, 2007</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales to AEP Power Pool</td>
<td>$ 161,969</td>
<td>$ 124,903</td>
<td>$ 237,035</td>
<td>$ 671,106</td>
<td>$ N/A</td>
<td>$ N/A</td>
</tr>
<tr>
<td>Direct Sales to East Affiliates</td>
<td>75,843</td>
<td>-</td>
<td>-</td>
<td>69,693</td>
<td>2,717</td>
<td>2,172</td>
</tr>
<tr>
<td>Direct Sales to West Affiliates</td>
<td>17,366</td>
<td>9,930</td>
<td>10,136</td>
<td>11,729</td>
<td>51,913</td>
<td>35,147</td>
</tr>
<tr>
<td>Natural Gas Contracts with AEPES</td>
<td>4,440</td>
<td>697</td>
<td>(1,123)</td>
<td>343</td>
<td>1,405</td>
<td>1,657</td>
</tr>
<tr>
<td>Other</td>
<td>3,448</td>
<td>7,582</td>
<td>2,366</td>
<td>4,181</td>
<td>13,071</td>
<td>14,126</td>
</tr>
<tr>
<td><strong>Total Revenues</strong></td>
<td>$ 263,066</td>
<td>$ 143,112</td>
<td>$ 248,414</td>
<td>$ 757,052</td>
<td>$ 69,106</td>
<td>$ 53,102</td>
</tr>
</tbody>
</table>

H-82
The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Related Party Purchases</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year Ended December 31, 2008</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchases from AEP Power Pool</td>
<td>$783,048</td>
<td>$334,983</td>
<td>$135,056</td>
<td>$135,514</td>
<td>$N/A</td>
<td>$N/A</td>
</tr>
<tr>
<td>Purchases from West System Pool</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>-</td>
<td>2,867</td>
</tr>
<tr>
<td>Purchases from AEPEP</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>-</td>
<td>28</td>
</tr>
<tr>
<td>Direct Purchases from East Affiliates</td>
<td>-</td>
<td>77,296</td>
<td>247,931</td>
<td>-</td>
<td>25,851</td>
<td>25,333</td>
</tr>
<tr>
<td>Direct Purchases from West Affiliates</td>
<td>2,143</td>
<td>1,239</td>
<td>1,195</td>
<td>1,483</td>
<td>33,493</td>
<td>90,545</td>
</tr>
<tr>
<td>Gas Purchases from AEPES</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3,689</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Purchases</strong></td>
<td>$785,191</td>
<td>$413,518</td>
<td>$384,182</td>
<td>$140,686</td>
<td>$59,344</td>
<td>$118,773</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Related Party Purchases</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year Ended December 31, 2007</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchases from AEP Power Pool</td>
<td>$597,951</td>
<td>$297,934</td>
<td>$133,885</td>
<td>$110,579</td>
<td>$N/A</td>
<td>$N/A</td>
</tr>
<tr>
<td>Direct Purchases from East Affiliates</td>
<td>733</td>
<td>63,803</td>
<td>207,160</td>
<td>-</td>
<td>31,916</td>
<td>20,982</td>
</tr>
<tr>
<td>Direct Purchases from West Affiliates</td>
<td>1,609</td>
<td>911</td>
<td>936</td>
<td>1,080</td>
<td>34,408</td>
<td>51,913</td>
</tr>
<tr>
<td>Gas Purchases from AEPES</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>13,449</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Purchases</strong></td>
<td>$600,293</td>
<td>$362,648</td>
<td>$341,981</td>
<td>$125,108</td>
<td>$66,324</td>
<td>$72,895</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Related Party Purchases</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Year Ended December 31, 2006</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchases from AEP Power Pool</td>
<td>$492,619</td>
<td>$365,425</td>
<td>$126,345</td>
<td>$108,151</td>
<td>$N/A</td>
<td>$N/A</td>
</tr>
<tr>
<td>Direct Purchases from East Affiliates</td>
<td>-</td>
<td>-</td>
<td>216,723</td>
<td>-</td>
<td>37,504</td>
<td>27,257</td>
</tr>
<tr>
<td>Direct Purchases from West Affiliates</td>
<td>137</td>
<td>85</td>
<td>88</td>
<td>104</td>
<td>31,902</td>
<td>47,201</td>
</tr>
<tr>
<td>Gas Purchases from AEPES</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>5,396</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Purchases</strong></td>
<td>$492,756</td>
<td>$365,510</td>
<td>$343,156</td>
<td>$113,651</td>
<td>$69,406</td>
<td>$74,458</td>
</tr>
</tbody>
</table>

N/A = Not Applicable

The above summarized related party revenues and expenses are reported as consolidated and are presented as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the income statements of each AEP Power Pool member. Since all of the above pool members are included in AEP’s consolidated results, the above summarized related party transactions are eliminated in total in AEP’s consolidated revenues and expenses.
AEP System Transmission Pool

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 companies and AEP West companies zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Equalization Agreement (TEA) and the Transmission Coordination Agreement (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 AEP System dispatch costs.

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company’s MLR.

The following table shows the net charges (credits) allocated among the Registrant Subsidiaries, party to the TEA, during the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td></td>
<td>$ (29,146)</td>
<td>$ (24,900)</td>
<td>$ (16,000)</td>
</tr>
<tr>
<td>CSPCo</td>
<td></td>
<td>55,273</td>
<td>51,900</td>
<td>46,200</td>
</tr>
<tr>
<td>I&amp;M</td>
<td></td>
<td>(37,398)</td>
<td>(34,600)</td>
<td>(37,300)</td>
</tr>
<tr>
<td>OPCo</td>
<td></td>
<td>13,294</td>
<td>8,500</td>
<td>9,100</td>
</tr>
</tbody>
</table>

The net charges (credits) shown above are recorded in Other Operation on the respective income statements.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo).

The following table shows the net charges (credits) allocated among parties to the TCA pursuant to the SPP OATT protocols as described above during the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31,</th>
<th>2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td></td>
<td>$ 8,200</td>
<td>$ 500</td>
<td>$ 1,800</td>
</tr>
<tr>
<td>SWEPCo</td>
<td></td>
<td>(8,200)</td>
<td>(500)</td>
<td>(1,900)</td>
</tr>
</tbody>
</table>

The net charges (credits) shown above are recorded in the Other Operation on PSO’s and SWEPCo’s respective income statements.
Assignment from SWEPCo, TCC and TNC to AEPEP

On March 1, 2008, SWEPCo, TCC and TNC assigned a 20-year Purchase Power Agreement (PPA) to AEPEP. In addition to the PPA assignment, an intercompany agreement was executed between AEPEP and SWEPCo to provide SWEPCo with future margins related to its share. The PPA and intercompany agreements are effective through 2019. SWEPCo recorded revenue of $903 thousand from AEPEP in Sales to AEP Affiliates on its 2008 Consolidated Statement of Income.

ERCOT Contracts Transferred to AEPEP

Effective January 1, 2007, PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEPEP and entered into intercompany financial and physical purchase and sale agreements with AEPEP. This was done to lock in PSO and SWEPCo’s margins on ERCOT trading and marketing contracts and to transfer the future associated commodity price and credit risk to AEPEP. The contracts will mature in December 2009.

PSO and SWEPCo have historically presented third party ERCOT trading and marketing activity on a net basis in Revenues - Electric Generation, Transmission and Distribution. The applicable ERCOT third party trading and marketing contracts that were not transferred to AEPEP will remain until maturity on PSO’s and SWEPCo’s balance sheets and will be presented on a net basis in Sales to AEP Affiliates on PSO’s and SWEPCo’s respective income statements.

The following tables indicate the sales to AEPEP and the amounts reclassified from third party to affiliate:

<table>
<thead>
<tr>
<th>Year Ended December 31, 2008</th>
<th>Company</th>
<th>Net Settlement with AEPEP</th>
<th>Third Party Amounts Reclassified to Affiliate</th>
<th>Net Amount Included in Sales to AEP Affiliates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PSO</td>
<td>$79,445</td>
<td>$(76,000)</td>
<td>$3,445</td>
</tr>
<tr>
<td></td>
<td>SWEPCo</td>
<td>84,095</td>
<td>(80,032)</td>
<td>4,063</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year Ended December 31, 2007</th>
<th>Company</th>
<th>Net Settlement with AEPEP</th>
<th>Third Party Amounts Reclassified to Affiliate</th>
<th>Net Amount Included in Sales to AEP Affiliates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PSO</td>
<td>$163,922</td>
<td>$(155,274)</td>
<td>$8,648</td>
</tr>
<tr>
<td></td>
<td>SWEPCo</td>
<td>202,135</td>
<td>(191,940)</td>
<td>10,195</td>
</tr>
</tbody>
</table>

The following table indicates the affiliated portion of risk management assets and liabilities reflected on PSO’s and SWEPCo’s respective balance sheets associated with these contracts:

<table>
<thead>
<tr>
<th>Current</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>SWEPCo</td>
<td>PSO</td>
</tr>
<tr>
<td>Risk Management Assets</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>Risk Management Liabilities</td>
<td>1,631</td>
<td>1,923</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Noncurrent</th>
<th>December 31, 2008</th>
<th>December 31, 2007</th>
</tr>
</thead>
</table>
| SPP Customers and Assets Transferred from TNC to SWEPCo

SWEPCo’s and approximately 3% of TNC’s businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCo L.P.’s (a subsidiary of AEP C&I Company, LLC) customers and TNC’s facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007 and were recorded at net book value of $12 million.
**Equipment Transferred from AEP Pro Serv, Inc. to SWEPCo**

During the fourth quarter of 2008, AEP Pro Serv, Inc. transferred $37 million of refurbished turbines and related equipment to SWEPCo for installation at its Stall Unit at its Arsenal Hill Plant. SWEPCo recorded the transfer in CWIP on its 2008 Consolidated Balance Sheet.

**Natural Gas Contracts with DETM**

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies and PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. The following table represents the Registrant Subsidiaries’ risk management liabilities related to DETM at December 31:

<table>
<thead>
<tr>
<th>Company</th>
<th>December 31, 2008 (in thousands)</th>
<th>December 31, 2007 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$5,230</td>
<td>$(9,439)</td>
</tr>
<tr>
<td>CSPCo</td>
<td>$(2,937)</td>
<td>$(5,470)</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>$(2,842)</td>
<td>$(5,255)</td>
</tr>
<tr>
<td>OPCo</td>
<td>$(3,637)</td>
<td>$(6,373)</td>
</tr>
<tr>
<td>PSO</td>
<td>$(149)</td>
<td>$(331)</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>$(175)</td>
<td>$(390)</td>
</tr>
</tbody>
</table>

**Fuel Agreement between OPCo and AEPES**

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. The related purchases of gas managed by AEPES were as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31, 2008 (in thousands)</th>
<th>Years Ended December 31, 2007 (in thousands)</th>
<th>Years Ended December 31, 2006 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$1,204</td>
<td>$4,377</td>
<td>$1,660</td>
</tr>
<tr>
<td>CSPCo</td>
<td>707</td>
<td>2,483</td>
<td>1,016</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>681</td>
<td>2,553</td>
<td>1,065</td>
</tr>
<tr>
<td>OPCo</td>
<td>840</td>
<td>3,106</td>
<td>1,257</td>
</tr>
</tbody>
</table>

These purchases are reflected in Purchased Electricity for Resale on the respective income statements.

**Unit Power Agreements (UPA)**

**Lawrenceburg UPA between CSPCo and AEGCo**

In March 2007, CSPCo and AEGCo entered into a 10-year UPA for the entire output from the Lawrenceburg Generating Station effective with AEGCo’s purchase of the plant in May 2007. The UPA has an option for an additional 2-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, CSPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.
**I&M UPA between AEGCo and I&M**

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

**KPCo UPA between AEGCo and KPCo**

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement ends in December 2022. See “Affiliated Revenues and Purchases” section of this note.

**Jointly-Owned Electric Utility Plants**

APCo and OPCo jointly own the Amos Plant and the Sporn Plant. The costs of operating these facilities are apportioned between owners based on ownership interests. Each company’s share of these costs is included in the appropriate expense accounts on its respective Consolidated Statements of Income. Each company’s investment in these plants is included in Property, Plant and Equipment on its respective Consolidated Balance Sheets.

AEGCo and I&M jointly own one generating unit and jointly lease the other generating unit of the Rockport Plant. The costs of operating this facility are equally apportioned between AEGCo and I&M since each company has a 50% interest. Each company’s share of costs is included in the appropriate expense accounts on its respective income statements. Each company’s investment in these plants is included in Property, Plant and Equipment on its respective balance sheets.

PSO and TNC jointly own the Oklaunion Plant along with two nonaffiliated companies. TCC sold its share to one of the nonaffiliated companies in February 2007. The costs of operating the facility are apportioned between owners based on ownership interests. Each company’s share of these costs is included in the appropriate expense accounts on its respective income statements. PSO’s and TNC’s investment in this plant is included in Property, Plant and Equipment on its respective balance sheets.

**Cook Coal Terminal**

In 2008, 2007 and 2006, Cook Coal Terminal, a division of OPCo, performed coal transloading services at cost for APCo and I&M. OPCo included revenues for these services in Other-Affiliated and expenses in Other Operation on its Consolidated Statements of Income. The coal transloading revenues were as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31, 2008</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$ 1,000</td>
<td>$ 53</td>
<td>$ 899</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>15,368</td>
<td>18,364</td>
<td>15,869</td>
</tr>
</tbody>
</table>

APCo and I&M recorded the cost of the transloading services in Fuel on their respective Consolidated Balance Sheets.

In addition, Cook Coal Terminal provided coal transloading services for OVEC in 2008, 2007 and 2006. OPCo recorded revenue as Other – Nonaffiliated on its Consolidated Statements of Income in the amounts of $59 thousand, $290 thousand and $172 thousand in 2008, 2007 and 2006, respectively. OVEC is 43.47% owned by AEP (includes CSPCo’s 4.3% ownership of OVEC).
In 2008, 2007 and 2006, Cook Coal Terminal also performed railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo includes revenues for these services in Sales to AEP Affiliates and expenses in Other Operation on its Consolidated Statements of Income. The railcar maintenance revenues were as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
<th>2006 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$39</td>
<td>$8</td>
<td>$278</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2,720</td>
<td>2,490</td>
<td>2,491</td>
</tr>
<tr>
<td>PSO</td>
<td>1,160</td>
<td>307</td>
<td>905</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>434</td>
<td>1,479</td>
<td>433</td>
</tr>
</tbody>
</table>

APCo, I&M, PSO and SWEPCo record the cost of the railcar maintenance services in Fuel on their respective balance sheets.

**SWEPCo Railcar Facility**

SWEPCo operates a railcar maintenance facility in Alliance, Nebraska. The facility performs maintenance on its own railcars as well as railcars belonging to I&M, PSO and third parties. SWEPCo billed I&M $2.5 million and $2.2 million for railcar services provided in 2008 and 2007, respectively, and billed PSO $553 thousand and $755 thousand in 2008 and 2007, respectively. These billings, for SWEPCo, and costs, for I&M and PSO, are recorded in Fuel on the respective balance sheets.

**I&M Barging, Urea Transloading and Other Services**

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NOx emissions at certain generation plants in the AEP System. I&M records revenues from barging, transloading and other services as Other – Affiliated on its Consolidated Statements of Income. The affiliated companies record these costs paid to I&M as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008 (in millions)</th>
<th>2007 (in millions)</th>
<th>2006 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I&amp;M – Revenues</td>
<td>$103.4</td>
<td>$49.1</td>
<td>$47.9</td>
</tr>
<tr>
<td>AEGCo – Expense</td>
<td>17.0</td>
<td>9.2</td>
<td>14.9</td>
</tr>
<tr>
<td>APCo – Expense</td>
<td>27.1</td>
<td>16.6</td>
<td>14.5</td>
</tr>
<tr>
<td>KPCo – Expense</td>
<td>-</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>OPCo – Expense</td>
<td>40.9</td>
<td>7.1</td>
<td>2.1</td>
</tr>
<tr>
<td>AEP River Operations LLC – Expense (Nonutility Subsidiary of AEP)</td>
<td>18.4</td>
<td>16.1</td>
<td>16.3</td>
</tr>
</tbody>
</table>

In addition, I&M provided transloading services to OVEC. I&M recorded revenue of $3 thousand, $89 thousand and $121 thousand for 2008, 2007 and 2006, respectively, in Other – Nonaffiliated on its Consolidated Statements of Income.

**Services Provided by AEP River Operations LLC (formerly known as MEMCO)**

AEP River Operations LLC provides services for barge towing, chartering and general and administrative expenses to I&M. The costs are recorded by I&M as Other Operation expense. For the years ended December 31, 2008, 2007 and 2006, I&M recorded expenses of $37 million, $18 million and $16 million, respectively, for these activities.
Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008 (in thousands)</th>
<th>2007 (in thousands)</th>
<th>2006 (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEGCo</td>
<td>$138</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>CSPCo</td>
<td>682</td>
<td>505</td>
<td>617</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2,714</td>
<td>2,464</td>
<td>1,826</td>
</tr>
<tr>
<td>KPCo</td>
<td>1,183</td>
<td>167</td>
<td>181</td>
</tr>
<tr>
<td>OPCo</td>
<td>1,944</td>
<td>1,999</td>
<td>2,831</td>
</tr>
<tr>
<td>PSO</td>
<td>1,225</td>
<td>317</td>
<td>801</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>288</td>
<td>44</td>
<td>2</td>
</tr>
</tbody>
</table>

In addition, APCo billed OVEC and IKEC a total of $303 thousand, $898 thousand and $951 thousand for 2008, 2007 and 2006, respectively.

Affiliate Railcar Agreement

Certain AEP subsidiaries have an agreement providing for the use of each other’s leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. The AEP subsidiaries record these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on their balance sheets and such costs are recoverable from customers. The following tables show the net effect of the railcar agreement on the AEP subsidiaries’ respective balance sheets:

### Year Ended December 31, 2008

<table>
<thead>
<tr>
<th>Billing Company</th>
<th>AEP Transportation (a)</th>
<th>APCo (in thousands)</th>
<th>I&amp;M (in thousands)</th>
<th>OPCo (in thousands)</th>
<th>PSO (in thousands)</th>
<th>SWEPCo (in thousands)</th>
<th>Total (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$2</td>
<td>$-</td>
<td>$110</td>
<td>$1,754</td>
<td>$12</td>
<td>$30</td>
<td>$1,908</td>
</tr>
<tr>
<td>CSPCo</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>6</td>
<td>523</td>
<td>-</td>
<td>1,105</td>
<td>328</td>
<td>1,155</td>
<td>3,117</td>
</tr>
<tr>
<td>KPCo</td>
<td>-</td>
<td>274</td>
<td>-</td>
<td>332</td>
<td>-</td>
<td>606</td>
<td>1,606</td>
</tr>
<tr>
<td>OPCo</td>
<td>1</td>
<td>1,176</td>
<td>376</td>
<td>-</td>
<td>13</td>
<td>60</td>
<td>1,626</td>
</tr>
<tr>
<td>PSO</td>
<td>10</td>
<td>5</td>
<td>1,316</td>
<td>177</td>
<td>-</td>
<td>476</td>
<td>1,984</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>(5)</td>
<td>-</td>
<td>2,543</td>
<td>874</td>
<td>212</td>
<td>-</td>
<td>3,624</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$14</strong></td>
<td><strong>$1,978</strong></td>
<td><strong>$4,345</strong></td>
<td><strong>$4,242</strong></td>
<td><strong>$565</strong></td>
<td><strong>$1,722</strong></td>
<td><strong>$12,866</strong></td>
</tr>
</tbody>
</table>

### Year Ended December 31, 2007

<table>
<thead>
<tr>
<th>Billing Company</th>
<th>AEP Transportation (a)</th>
<th>APCo (in thousands)</th>
<th>I&amp;M (in thousands)</th>
<th>OPCo (in thousands)</th>
<th>PSO (in thousands)</th>
<th>SWEPCo (in thousands)</th>
<th>Total (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$1,977</td>
<td>$-</td>
<td>$-</td>
<td>$1,977</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>533</td>
<td>-</td>
<td>-</td>
<td>829</td>
<td>387</td>
<td>595</td>
<td>2,344</td>
</tr>
<tr>
<td>KPCo</td>
<td>-</td>
<td>90</td>
<td>-</td>
<td>183</td>
<td>-</td>
<td>-</td>
<td>273</td>
</tr>
<tr>
<td>OPCo</td>
<td>11</td>
<td>945</td>
<td>429</td>
<td>-</td>
<td>16</td>
<td>17</td>
<td>1,418</td>
</tr>
<tr>
<td>PSO</td>
<td>530</td>
<td>-</td>
<td>932</td>
<td>137</td>
<td>-</td>
<td>223</td>
<td>1,822</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>1,384</td>
<td>-</td>
<td>2,266</td>
<td>513</td>
<td>197</td>
<td>-</td>
<td>4,360</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$2,458</strong></td>
<td><strong>$1,035</strong></td>
<td><strong>$3,627</strong></td>
<td><strong>$3,639</strong></td>
<td><strong>$600</strong></td>
<td><strong>$835</strong></td>
<td><strong>$12,194</strong></td>
</tr>
</tbody>
</table>

(a) AEP Transportation is a 100%-owned nonutility subsidiary of AEP.
OPCo Indemnification Agreement with AEP Resources

OPCo had an indemnification agreement with AEP Resources, Inc. (AEPR), a nonutility subsidiary of AEP, whereby AEPR held OPCo harmless from market exposure related to OPCo’s Power Purchase and Sale Agreement dated November 15, 2000 with Dow Chemical Company. In 2006, AEPR paid OPCo $14.9 million which is reported in OPCo’s Other Operation on its Consolidated Statement of Income. As a result of the sale of the Plaquemine Cogeneration Facility and subsequent termination of OPCo’s Power Purchase and Sale Agreement in November 2006, there were no indemnification payments in 2008 or 2007.

Purchased Power from OVEC

The amounts of power purchased by the Registrant Subsidiaries from OVEC, which is 43.47% owned by AEP (includes CSPCo’s 4.3% ownership of OVEC), for the years ended December 31, 2008, 2007 and 2006 were:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
<td>2006</td>
</tr>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td>(in thousands)</td>
</tr>
<tr>
<td>APCo</td>
<td>$94,874</td>
<td>$81,612</td>
<td>$82,422</td>
</tr>
<tr>
<td>CSPCo</td>
<td>26,853</td>
<td>23,102</td>
<td>22,821</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>47,465</td>
<td>40,827</td>
<td>38,961</td>
</tr>
<tr>
<td>OPCo</td>
<td>93,661</td>
<td>80,561</td>
<td>78,579</td>
</tr>
</tbody>
</table>

The amounts shown above are recoverable from customers and are included in Purchased Electricity for Resale on the respective income statements.

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues on the respective income statements. The agreement expired in May 2008 and subsequently ended in December 2008. The following table shows the amounts recorded for the years ended December 31, 2008, 2007 and 2006:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31,</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2007</td>
<td>2006</td>
</tr>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td>(in thousands)</td>
</tr>
<tr>
<td>APCo</td>
<td>$17,795</td>
<td>$9,830</td>
<td>$11,284</td>
</tr>
<tr>
<td>CSPCo</td>
<td>10,381</td>
<td>5,553</td>
<td>6,915</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>9,999</td>
<td>5,530</td>
<td>7,189</td>
</tr>
<tr>
<td>OPCo</td>
<td>12,359</td>
<td>6,526</td>
<td>8,576</td>
</tr>
</tbody>
</table>
Purchased Power from Sweeny

On behalf of the AEP West companies, CSPCo entered into a ten-year Power Purchase Agreement (PPA) with Sweeny, which was 50% owned by AEP. The PPA was for unit contingent power up to a maximum of 315 MW from January 1, 2005 through December 31, 2014. The delivery point for the power under the PPA was in TCC’s system. The power was sold in ERCOT. Prior to May 1, 2006, the purchase of Sweeny power and its sale to nonaffiliates was shared among the AEP West companies under the CSW Operating Agreement. After May 1, 2006, the purchases and sales were shared between PSO and SWEPCo. See “CSW Operating Agreement” section of this note. In April 2007, AEP Energy Partners (AEPEP) was assigned the Sweeny PPA from CSPCo and became responsible for purchasing the Sweeny power instead of PSO and SWEPCo. In October 2007, AEP sold its 50% interest in the Sweeny facility along with the ten year PPA to Conoco Phillips. The purchases from Sweeny were:

<table>
<thead>
<tr>
<th>Company</th>
<th>2007</th>
<th>2006</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>$13,955</td>
<td>$53,354</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>16,443</td>
<td>62,794</td>
</tr>
</tbody>
</table>

The amounts shown above are recorded in Purchased Electricity for Resale on PSO’s and SWEPCo’s respective income statements.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

**Year Ended December 31, 2008**

<table>
<thead>
<tr>
<th>Companies</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo to CSPCo</td>
<td>$858</td>
</tr>
<tr>
<td>APCo to I&amp;M</td>
<td>2,720</td>
</tr>
<tr>
<td>APCo to OPCo</td>
<td>615</td>
</tr>
<tr>
<td>CSPCo to PSO</td>
<td>180</td>
</tr>
<tr>
<td>I&amp;M to APCo</td>
<td>653</td>
</tr>
<tr>
<td>I&amp;M to KPCo</td>
<td>444</td>
</tr>
<tr>
<td>I&amp;M to OPCo</td>
<td>1,992</td>
</tr>
<tr>
<td>I&amp;M to PSO</td>
<td>666</td>
</tr>
<tr>
<td>OPCo to I&amp;M</td>
<td>1,800</td>
</tr>
<tr>
<td>OPCo to PSO</td>
<td>259</td>
</tr>
<tr>
<td>PSO to I&amp;M</td>
<td>646</td>
</tr>
<tr>
<td>TCC to APCo</td>
<td>220</td>
</tr>
</tbody>
</table>

**Year Ended December 31, 2007**

<table>
<thead>
<tr>
<th>Companies</th>
<th>(in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo to I&amp;M</td>
<td>2,893</td>
</tr>
<tr>
<td>APCo to OPCo</td>
<td>2,695</td>
</tr>
<tr>
<td>I&amp;M to PSO</td>
<td>1,729</td>
</tr>
<tr>
<td>I&amp;M to SWEPCo</td>
<td>212</td>
</tr>
<tr>
<td>OPCo to I&amp;M</td>
<td>2,070</td>
</tr>
<tr>
<td>OPCo to KPCo</td>
<td>133</td>
</tr>
<tr>
<td>OPCo to WPCo</td>
<td>281</td>
</tr>
<tr>
<td>PSO to SWEPCo</td>
<td>228</td>
</tr>
<tr>
<td>SWEPCo to PSO</td>
<td>212</td>
</tr>
<tr>
<td>TNC to SWEPCo</td>
<td>11,649</td>
</tr>
</tbody>
</table>
### Companies

<table>
<thead>
<tr>
<th>Purchaser</th>
<th>APCo to OPCo</th>
<th>CSPCo to OPCo</th>
<th>I&amp;M to CSPCo</th>
<th>I&amp;M to SWEPCo</th>
<th>I&amp;M to WPCo</th>
<th>KPCo to APCo</th>
<th>OPCo to APCo</th>
<th>OPCo to KPCo</th>
<th>OPCo to PSO</th>
<th>OPCo to PSO</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$1,037</td>
<td>$592</td>
<td>$173</td>
<td>$111</td>
<td>$201</td>
<td>$191</td>
<td>$3,822</td>
<td>$1,324</td>
<td>$760</td>
<td>$1,001</td>
</tr>
<tr>
<td>CSPCo</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>I&amp;M</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SWEPCo</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WPCo</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

In addition, certain AEP subsidiaries had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

### Year Ended December 31, 2008

<table>
<thead>
<tr>
<th>Seller</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>KGPCo</th>
<th>KPCo</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>TCC</th>
<th>TNC</th>
<th>WPCo</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$ -</td>
<td>$ 27</td>
<td>$ 24</td>
<td>$ 386</td>
<td>$ 112</td>
<td>$ 206</td>
<td>$ 9</td>
<td>$ 164</td>
<td>$ 73</td>
<td>$  -</td>
<td>$  -</td>
<td>$ 1,001</td>
</tr>
<tr>
<td>CSPCo</td>
<td>18</td>
<td>-</td>
<td>15</td>
<td>-</td>
<td>-</td>
<td>580</td>
<td>2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>620</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>2</td>
<td>86</td>
<td>-</td>
<td>-</td>
<td>15</td>
<td>270</td>
<td>25</td>
<td>2</td>
<td>5</td>
<td>-</td>
<td>22</td>
<td>427</td>
</tr>
<tr>
<td>KGPCo</td>
<td>253</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>253</td>
</tr>
<tr>
<td>KPCo</td>
<td>354</td>
<td>11</td>
<td>16</td>
<td>6</td>
<td>-</td>
<td>121</td>
<td>2</td>
<td>33</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>543</td>
</tr>
<tr>
<td>OPCo</td>
<td>249</td>
<td>3,446</td>
<td>613</td>
<td>-</td>
<td>95</td>
<td>-</td>
<td>2</td>
<td>16</td>
<td>11</td>
<td>562</td>
<td>5,008</td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>1</td>
<td>98</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>4</td>
<td>124</td>
<td>-</td>
<td>25</td>
<td>-</td>
<td>252</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3</td>
<td>655</td>
<td>-</td>
<td>13</td>
<td>-</td>
<td>9</td>
<td>680</td>
</tr>
<tr>
<td>TCC</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>9</td>
<td>535</td>
<td>-</td>
<td>494</td>
<td>-</td>
<td>1,040</td>
</tr>
<tr>
<td>TNC</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>9</td>
<td>28</td>
<td>334</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>397</td>
</tr>
<tr>
<td>WPCo</td>
<td>-</td>
<td>6</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>152</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>159</td>
</tr>
<tr>
<td>Total</td>
<td>$ 878</td>
<td>$ 3,674</td>
<td>$ 669</td>
<td>$ 392</td>
<td>$ 222</td>
<td>$ 1,346</td>
<td>$ 730</td>
<td>$ 869</td>
<td>$ 472</td>
<td>$ 539</td>
<td>$ 589</td>
<td>$ 10,380</td>
</tr>
</tbody>
</table>

### Year Ended December 31, 2007

<table>
<thead>
<tr>
<th>Seller</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>KGPCo</th>
<th>KPCo</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>TCC</th>
<th>TNC</th>
<th>WPCo</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$ -</td>
<td>$ 38</td>
<td>$ 61</td>
<td>$ 578</td>
<td>$ 518</td>
<td>$ 281</td>
<td>$ 115</td>
<td>$ 33</td>
<td>$ 61</td>
<td>$  -</td>
<td>$  13</td>
<td>$ 1,698</td>
</tr>
<tr>
<td>CSPCo</td>
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<td>-</td>
<td>6</td>
<td>1,132</td>
<td>31</td>
<td>20</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,200</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>22</td>
<td>79</td>
<td>3</td>
<td>4</td>
<td>436</td>
<td>54</td>
<td>29</td>
<td>4</td>
<td>20</td>
<td>-</td>
<td>651</td>
<td></td>
</tr>
<tr>
<td>KGPCo</td>
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<td>-</td>
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<td>1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>248</td>
</tr>
<tr>
<td>KPCo</td>
<td>345</td>
<td>38</td>
<td>21</td>
<td>10</td>
<td>-</td>
<td>124</td>
<td>85</td>
<td>7</td>
<td>-</td>
<td>-</td>
<td>66</td>
<td>696</td>
</tr>
<tr>
<td>OPCo</td>
<td>456</td>
<td>2,978</td>
<td>614</td>
<td>-</td>
<td>197</td>
<td>-</td>
<td>3</td>
<td>145</td>
<td>6</td>
<td>-</td>
<td>299</td>
<td>4,698</td>
</tr>
<tr>
<td>PSO</td>
<td>20</td>
<td>77</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>73</td>
<td>-</td>
<td>2</td>
<td>-</td>
<td>172</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>-</td>
<td>3</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>262</td>
<td>-</td>
<td>26</td>
<td>13</td>
<td>-</td>
<td>305</td>
</tr>
<tr>
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<td>-</td>
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<td>1</td>
<td>76</td>
<td>-</td>
<td>763</td>
<td>-</td>
<td>913</td>
<td></td>
</tr>
<tr>
<td>TNC</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>10</td>
<td>456</td>
<td>199</td>
<td>-</td>
<td>666</td>
</tr>
<tr>
<td>WPCo</td>
<td>-</td>
<td>1</td>
<td>6</td>
<td>-</td>
<td>5</td>
<td>132</td>
<td>-</td>
<td>3</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>147</td>
</tr>
<tr>
<td>Total</td>
<td>$1,109</td>
<td>$3,224</td>
<td>$717</td>
<td>$591</td>
<td>$731</td>
<td>$2,147</td>
<td>$561</td>
<td>$842</td>
<td>$296</td>
<td>$778</td>
<td>$398</td>
<td>$11,394</td>
</tr>
</tbody>
</table>
### Year Ended December 31, 2006

<table>
<thead>
<tr>
<th>Seller</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>KGPCo</th>
<th>KPCo</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
<th>TCC</th>
<th>TNC</th>
<th>WPCo</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$3,206</td>
<td>$157</td>
<td>$1,631</td>
<td>$459</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$4,021</td>
</tr>
<tr>
<td>CSPCo</td>
<td>$17</td>
<td>$1,617</td>
<td>$2,019</td>
<td>$3,206</td>
<td>$676</td>
<td>$545</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>I&amp;M</td>
<td>$187</td>
<td></td>
<td></td>
<td>$669</td>
<td>$187</td>
<td>$157</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KGPCo</td>
<td>$86</td>
<td>$86</td>
<td></td>
<td>$1,186</td>
<td>$1,186</td>
<td>$295</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KPCo</td>
<td>$1,750</td>
<td>$2,545</td>
<td>$910</td>
<td></td>
<td>$504</td>
<td>$122</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPCo</td>
<td>$1,750</td>
<td>$2,545</td>
<td>$910</td>
<td></td>
<td>$504</td>
<td>$122</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>$16</td>
<td></td>
<td></td>
<td>$16</td>
<td></td>
<td>$16</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$24,071</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>$16</td>
<td></td>
<td></td>
<td>$16</td>
<td></td>
<td>$16</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TCC</td>
<td>$12</td>
<td></td>
<td></td>
<td>$12</td>
<td></td>
<td>$12</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TNC</td>
<td>$7</td>
<td></td>
<td></td>
<td>$7</td>
<td></td>
<td>$7</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WPCo</td>
<td>$7</td>
<td>$28</td>
<td>$21</td>
<td>$3</td>
<td>$247</td>
<td>$8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$4,316</td>
<td>$2,710</td>
<td>$1,186</td>
<td>$725</td>
<td>$3,732</td>
<td>$5,265</td>
<td>$687</td>
<td>$1,221</td>
<td>$2,092</td>
<td>$1,268</td>
<td>$869</td>
<td>$24,071</td>
</tr>
</tbody>
</table>

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

**Global Borrowing Notes**

AEP issued long-term debt, portions of which were loaned to the Registrant Subsidiaries. The debt is reflected in Long-term Debt – Affiliated on the Registrant Subsidiaries’ respective balance sheets. AEP pays the interest on the global notes, but the Registrant Subsidiaries accrue interest for their respective share of the global borrowing and remit the interest to AEP. The accrued interest is reflected in either Accrued Interest or Other in the Current Liabilities section of the Registrant Subsidiaries’ respective balance sheets. APCo, CSPCo, OPCo, PSO and SWEPCo participated in the global borrowing arrangement during the reporting periods.

**Intercompany Billings**

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings between affiliated subsidiaries are capitalized or expensed depending on the nature of the services rendered.

**Variable Interest Entities**

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether they are the primary beneficiary of a VIE, each Registrant Subsidiary considers factors such as equity at risk, the amount of variability of the VIE the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. In addition, the Registrant Subsidiaries have not provided financial or other support that was not previously contractually required to any VIE.

SWEPCo is the primary beneficiary of Sabine and DHLC. OPCo is the primary beneficiary of JMG. APCo, CSPCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and CSPCo each hold a significant variable interest in AEGCo.
Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine’s only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee which is included in Fuel and Other Consumables Used for Electric Generation on SWEPCo’s Consolidated Statements of Income. Based on these facts, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo’s total billings from Sabine for the years ended December 31, 2008 and 2007 were $110 million and $95 million, respectively. See the tables below for the classification of Sabine’s assets and liabilities on SWEPCo’s Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC’s debt. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHLC. SWEPCo’s total billings from DHLC for the years ended December 31, 2008 and 2007 were $44 million and $35 million, respectively. These billings are included in Fuel and Other Consumables Used for Electric Generation on SWEPCo’s Consolidated Statements of Income. See the tables below for the classification of DHLC assets and liabilities on SWEPCo’s Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED VARIABLE INTEREST ENTITIES**

December 31, 2008

<table>
<thead>
<tr>
<th></th>
<th>Sabine (in millions)</th>
<th>DHLC (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Assets</td>
<td>$33</td>
<td>$22</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>117</td>
<td>33</td>
</tr>
<tr>
<td>Other Noncurrent Assets</td>
<td>24</td>
<td>11</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$174</td>
<td>$66</td>
</tr>
<tr>
<td><strong>LIABILITIES AND SHAREHOLDERS’ EQUITY</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>$32</td>
<td>$18</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>142</td>
<td>44</td>
</tr>
<tr>
<td>Common Shareholders’ Equity</td>
<td>-</td>
<td>4</td>
</tr>
<tr>
<td><strong>Total Liabilities and Shareholder’s Equity</strong></td>
<td>$174</td>
<td>$66</td>
</tr>
</tbody>
</table>

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED VARIABLE INTEREST ENTITIES**

December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>Sabine (in millions)</th>
<th>DHLC (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Assets</td>
<td>$24</td>
<td>$29</td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>97</td>
<td>41</td>
</tr>
<tr>
<td>Other Noncurrent Assets</td>
<td>25</td>
<td>13</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$146</td>
<td>$83</td>
</tr>
<tr>
<td><strong>LIABILITIES AND SHAREHOLDERS’ EQUITY</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>$14</td>
<td>$26</td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>130</td>
<td>54</td>
</tr>
<tr>
<td>Common Shareholder’s Equity</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total Liabilities and Shareholders’ Equity</strong></td>
<td>$146</td>
<td>$83</td>
</tr>
</tbody>
</table>
OPCo has a lease agreement with JMG to finance OPCo’s FGD system installed on OPCo’s Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo’s lease payments are the only form of repayment associated with JMG’s debt obligations even though OPCo does not guarantee JMG’s debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded that OPCo is the primary beneficiary and is required to consolidate JMG. OPCo’s total billings from JMG for the years ended December 31, 2008 and 2007 were $57 million and $46 million, respectively. See the tables below for the classification of JMG’s assets and liabilities on OPCo’s Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIE that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

### OHIO POWER COMPANY CONSOLIDATED VARIABLE INTEREST ENTITY

#### December 31, 2008

<table>
<thead>
<tr>
<th></th>
<th>(in millions)</th>
<th>JMG</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Assets</td>
<td>$ 11</td>
<td></td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>423</td>
<td></td>
</tr>
<tr>
<td>Other Noncurrent Assets</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$ 435</td>
<td></td>
</tr>
<tr>
<td><strong>LIABILITIES AND SHAREHOLDERS’ EQUITY</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>$ 161</td>
<td></td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>257</td>
<td></td>
</tr>
<tr>
<td>Common Shareholder’s Equity</td>
<td>17</td>
<td></td>
</tr>
<tr>
<td><strong>Total Liabilities and Shareholders’ Equity</strong></td>
<td>$ 435</td>
<td></td>
</tr>
</tbody>
</table>

### OHIO POWER COMPANY CONSOLIDATED VARIABLE INTEREST ENTITY

#### December 31, 2007

<table>
<thead>
<tr>
<th></th>
<th>(in millions)</th>
<th>JMG</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Assets</td>
<td>$ 5</td>
<td></td>
</tr>
<tr>
<td>Net Property, Plant and Equipment</td>
<td>443</td>
<td></td>
</tr>
<tr>
<td>Other Noncurrent Assets</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>$ 449</td>
<td></td>
</tr>
<tr>
<td><strong>LIABILITIES AND SHAREHOLDERS’ EQUITY</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>$ 98</td>
<td></td>
</tr>
<tr>
<td>Noncurrent Liabilities</td>
<td>335</td>
<td></td>
</tr>
<tr>
<td>Common Shareholder’s Equity</td>
<td>16</td>
<td></td>
</tr>
<tr>
<td><strong>Total Liabilities and Shareholders’ Equity</strong></td>
<td>$ 449</td>
<td></td>
</tr>
</tbody>
</table>

AEPSC provides certain managerial and professional services to AEP’s subsidiaries. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC’s cost. No AEP subsidiary has provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations by cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP’s subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. All Registrant Subsidiaries are considered to have a significant interest in the variability in AEPSC due to their activity in AEPSC’s cost reimbursement structure. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.
Total AEPSC billings to the Registrant Subsidiaries were as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008 (in millions)</th>
<th>2007 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$250</td>
<td>$232</td>
</tr>
<tr>
<td>CSPCo</td>
<td>136</td>
<td>114</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>148</td>
<td>138</td>
</tr>
<tr>
<td>OPCo</td>
<td>208</td>
<td>189</td>
</tr>
<tr>
<td>PSO</td>
<td>117</td>
<td>105</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>139</td>
<td>119</td>
</tr>
</tbody>
</table>

The carrying amount and classification of variable interest in AEPSC’s accounts payable as of December 31, 2008 and 2007 are as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008 As Reported in the Balance Sheet</th>
<th>Maximum Exposure</th>
<th>2007 As Reported in the Balance Sheet</th>
<th>Maximum Exposure</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$27</td>
<td>$27</td>
<td>$31</td>
<td>$31</td>
</tr>
<tr>
<td>CSPCo</td>
<td>15</td>
<td>15</td>
<td>17</td>
<td>17</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>14</td>
<td>14</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>OPCo</td>
<td>21</td>
<td>21</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td>PSO</td>
<td>10</td>
<td>10</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>14</td>
<td>14</td>
<td>16</td>
<td>16</td>
</tr>
</tbody>
</table>

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. In May 2007, AEGCo began leasing the Lawrenceburg Generating Station to CSPCo. AEP guarantees all the debt obligations of AEGCo. I&M and CSPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and CSPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. Due to the nature of the AEP Power Pool, there is a sharing of the cost of Rockport and Lawrenceburg Plants such that no member of the AEP Power Pool is the primary beneficiary of AEGCo’s Rockport or Lawrenceburg Plants. In the event AEGCo would require financing or other support outside the billings to I&M, CSPCo and KPCo, this financing would be provided by AEP. See “Rockport Lease” section of Note 13 for additional information regarding AEGCo’s lease.

Total billings from AEGCo are as follows:

<table>
<thead>
<tr>
<th>Year Ended December 31, 2008 (in millions)</th>
<th>2007 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSPCo</td>
<td>$114</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>248</td>
</tr>
</tbody>
</table>

The carrying amount and classification of variable interest in AEGCo’s accounts payable as of December 31, 2008 and 2007 are as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>2008 As Reported in the Consolidated Balance Sheet</th>
<th>Maximum Exposure</th>
<th>2007 As Reported in the Consolidated Balance Sheet</th>
<th>Maximum Exposure</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSPCo</td>
<td>$5</td>
<td>$5</td>
<td>$7</td>
<td>$7</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>23</td>
<td>23</td>
<td>21</td>
<td>21</td>
</tr>
</tbody>
</table>
16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

The Registrant Subsidiaries provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries:

### APCo

<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>Regulated</th>
<th>Nonregulated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property, Plant and Equipment</td>
<td>Accumulated Depreciation</td>
<td>Annual Composite Depreciation Rate</td>
</tr>
<tr>
<td>(in thousands)</td>
<td></td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>$3,708,850</td>
<td>$1,592,837</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,754,192</td>
<td>420,213</td>
</tr>
<tr>
<td>Distribution</td>
<td>2,499,974</td>
<td>511,242</td>
</tr>
<tr>
<td>CWIP</td>
<td>1,106,032</td>
<td>(18,514)</td>
</tr>
<tr>
<td>Other</td>
<td>325,147</td>
<td>157,491</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$9,394,195</td>
<td>$2,663,269</td>
</tr>
</tbody>
</table>

### Functional Class of Property

<table>
<thead>
<tr>
<th>Regulated</th>
<th>Nonregulated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>-</td>
</tr>
</tbody>
</table>

2007

<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>Regulated</th>
<th>Nonregulated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property, Plant and Equipment</td>
<td>Accumulated Depreciation</td>
<td>Annual Composite Depreciation Rate</td>
</tr>
<tr>
<td>(in thousands)</td>
<td></td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>$3,625,788</td>
<td>$1,531,999</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,675,081</td>
<td>408,126</td>
</tr>
<tr>
<td>Distribution</td>
<td>2,372,687</td>
<td>502,503</td>
</tr>
<tr>
<td>CWIP</td>
<td>713,063</td>
<td>(15,104)</td>
</tr>
<tr>
<td>Other</td>
<td>318,190</td>
<td>151,746</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$8,704,809</td>
<td>$2,579,270</td>
</tr>
</tbody>
</table>

### Functional Class of Property

<table>
<thead>
<tr>
<th>Regulated</th>
<th>Nonregulated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>-</td>
</tr>
</tbody>
</table>

2006

<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>Regulated</th>
<th>Nonregulated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property, Plant and Equipment</td>
<td>Accumulated Depreciation</td>
<td>Annual Composite Depreciation Rate</td>
</tr>
<tr>
<td>(in thousands)</td>
<td></td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>2.6%</td>
<td>40-121</td>
</tr>
<tr>
<td>Transmission</td>
<td>1.8%</td>
<td>25-87</td>
</tr>
<tr>
<td>Distribution</td>
<td>3.3%</td>
<td>11-52</td>
</tr>
<tr>
<td>Other</td>
<td>7.7%</td>
<td>24-55</td>
</tr>
</tbody>
</table>

N.M. = Not Meaningful
<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>2008</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Regulated</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nonregulated</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Transmission</td>
<td>574,018</td>
<td>219,121</td>
<td>2.3%</td>
<td>33-50</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,625,000</td>
<td>561,828</td>
<td>3.5%</td>
<td>12-56</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CWIP</td>
<td>152,889</td>
<td>(5,706)</td>
<td>N.M.</td>
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<td>242,029</td>
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<td>22,603</td>
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<td><strong>Total</strong></td>
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<td>$ 878,633</td>
<td>$ 2,590,688</td>
<td>$ 903,233</td>
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<tr>
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<td>(in years)</td>
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<tr>
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<td>-</td>
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<td>-</td>
<td>-</td>
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<tr>
<td>Transmission</td>
<td>510,107</td>
<td>209,369</td>
<td>2.3%</td>
<td>33-50</td>
<td>-</td>
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</tr>
<tr>
<td>Distribution</td>
<td>1,552,999</td>
<td>536,408</td>
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<td>-</td>
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<tr>
<td>CWIP</td>
<td>114,130</td>
<td>(5,773)</td>
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<td>N.M.</td>
<td>301,197</td>
<td>129</td>
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<td>Other</td>
<td>142,044</td>
<td>75,271</td>
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<td>56,432</td>
<td>21,176</td>
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<td><strong>Total</strong></td>
<td>$ 2,319,280</td>
<td>$ 815,275</td>
<td>$ 2,430,193</td>
<td>$ 882,518</td>
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<tr>
<th>Functional Class of Property</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>(in years)</td>
<td>(in years)</td>
<td>(in years)</td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>N.M.</td>
<td>N.M.</td>
<td>3.1%</td>
<td>40-59</td>
</tr>
<tr>
<td>Transmission</td>
<td>2.3%</td>
<td>33-50</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Distribution</td>
<td>3.5%</td>
<td>12-56</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>8.7%</td>
<td>N.M.</td>
<td>N.M.</td>
<td>N.M.</td>
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</table>

N.M. = Not Meaningful
### 2008 Functional Class of Property

<table>
<thead>
<tr>
<th>Property, Plant and Equipment</th>
<th>Accumulated Depreciation</th>
<th>Depreciable Life Ranges</th>
<th>Annual Composite Depreciation Rate</th>
<th>(in thousands)</th>
<th>(in years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>$ -</td>
<td>-</td>
<td>-</td>
<td>$ 6,025,277</td>
<td>2.7%</td>
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<tr>
<td>Transmission</td>
<td>1,111,637</td>
<td>453,235</td>
<td>2.3%</td>
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<tr>
<td>Distribution</td>
<td>1,472,906</td>
<td>392,468</td>
<td>3.9%</td>
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<td>2.7%</td>
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<tr>
<td>CWIP</td>
<td>121,412</td>
<td>(4,213)</td>
<td>N.M.</td>
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</tr>
<tr>
<td>Other</td>
<td>278,134</td>
<td>141,299</td>
<td>8.5%</td>
<td>N.M.</td>
<td>N.M.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 2,984,089</strong></td>
<td><strong>$ 928,789</strong></td>
<td></td>
<td><strong>$ 6,804,773</strong></td>
<td><strong>$ 2,140,200</strong></td>
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</table>

### 2007 Functional Class of Property

<table>
<thead>
<tr>
<th>Property, Plant and Equipment</th>
<th>Accumulated Depreciation</th>
<th>Depreciable Life Ranges</th>
<th>Annual Composite Depreciation Rate</th>
<th>(in thousands)</th>
<th>(in years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>$ -</td>
<td>-</td>
<td>-</td>
<td>$ 5,641,537</td>
<td>2.6%</td>
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<tr>
<td>Transmission</td>
<td>1,068,387</td>
<td>439,542</td>
<td>2.3%</td>
<td>27-70</td>
<td>2.6%</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,394,988</td>
<td>374,421</td>
<td>3.9%</td>
<td>12-55</td>
<td>2.6%</td>
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<tr>
<td>CWIP</td>
<td>73,902</td>
<td>(1,696)</td>
<td>N.M.</td>
<td>N.M.</td>
<td>N.M.</td>
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<tr>
<td>Other</td>
<td>188,382</td>
<td>88,522</td>
<td>8.6%</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>$ 2,725,659</strong></td>
<td><strong>$ 900,789</strong></td>
<td></td>
<td><strong>$ 6,414,698</strong></td>
<td><strong>$ 2,066,496</strong></td>
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### 2006 Functional Class of Property

<table>
<thead>
<tr>
<th>Property, Plant and Equipment</th>
<th>Accumulated Depreciation</th>
<th>Depreciable Life Ranges</th>
<th>Annual Composite Depreciation Rate</th>
<th>(in thousands)</th>
<th>(in years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>N.M.</td>
<td>N.M.</td>
<td>2.8%</td>
<td>35-61</td>
<td></td>
</tr>
<tr>
<td>Transmission</td>
<td>2.3%</td>
<td>27-70</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Distribution</td>
<td>3.9%</td>
<td>12-55</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>9.2%</td>
<td>N.M.</td>
<td>N.M.</td>
<td>N.M.</td>
<td>N.M.</td>
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</table>

N.M. = Not Meaningful
### 2008

<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>Property, Plant and Equipment Accumulated Depreciation</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
<th>Property, Plant and Equipment Accumulated Depreciation</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>$1,187,449 $684,712</td>
<td>2.9% 19-68</td>
<td>$621,033 $358,103</td>
<td>2.9% 30-37</td>
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</tr>
<tr>
<td>Transmission</td>
<td>786,731 $241,296</td>
<td>2.7% 44-65</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,400,952 $385,906</td>
<td>3.5% 19-56</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CWIP</td>
<td>586,863 $7,321</td>
<td>N.M. 7-45</td>
<td>315,903 $170,980</td>
<td>N.M. N.M.</td>
<td></td>
<td></td>
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<tr>
<td>Other</td>
<td>395,357 $180,478</td>
<td>7.1% 7-45</td>
<td>282,240</td>
<td>N.M. N.M.</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>$4,357,352 $1,485,071</strong></td>
<td><strong>2.9% 19-68</strong></td>
<td><strong>$1,219,176 $529,083</strong></td>
<td><strong>2.9% 30-37</strong></td>
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</table>

### 2007

<table>
<thead>
<tr>
<th>Functional Class of Property</th>
<th>Property, Plant and Equipment Accumulated Depreciation</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
<th>Property, Plant and Equipment Accumulated Depreciation</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
<td>(in thousands)</td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>$1,119,022 $652,802</td>
<td>3.0% 30-57</td>
<td>$624,176 $364,125</td>
<td>3.0% 30-57</td>
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<tr>
<td>Transmission</td>
<td>737,975 $231,406</td>
<td>2.7% 40-55</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Distribution</td>
<td>1,312,746 $374,084</td>
<td>3.5% 16-65</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>CWIP</td>
<td>279,717 $5,336</td>
<td>N.M. N.M.</td>
<td>171,511</td>
<td>N.M. N.M.</td>
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<tr>
<td>Other</td>
<td>323,543 $135,015</td>
<td>9.4% N.M.</td>
<td>308,222 $186,948</td>
<td>N.M. N.M.</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>$3,773,003 $1,387,971</strong></td>
<td><strong>3.0% 30-57</strong></td>
<td><strong>$1,103,909 $551,073</strong></td>
<td><strong>3.0% 30-57</strong></td>
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### 2006

<table>
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<th>Functional Class of Property</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in years)</td>
<td>(in years)</td>
<td>(in years)</td>
<td>(in years)</td>
</tr>
<tr>
<td>Production</td>
<td>3.1% 30-57</td>
<td>3.1% 30-57</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission</td>
<td>2.5% 40-55</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Distribution</td>
<td>3.1% 16-65</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Other</td>
<td>8.6% N.M.</td>
<td>N.M. N.M.</td>
<td>N.M. N.M.</td>
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N.M. = Not Meaningful
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<th>Functional Class of Property</th>
<th>Property, Plant and Equipment</th>
<th>Accumulated Depreciation</th>
<th>Annual Composite Depreciation Rate</th>
<th>Depreciable Life Ranges</th>
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<th>Depreciable Life Ranges</th>
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<tr>
<td>Production</td>
<td>$3,534,188</td>
<td>$2,024,445</td>
<td>1.6%</td>
<td>59-132</td>
<td>$1,266,716</td>
<td>$624,986</td>
<td>1.7%</td>
<td>9-70</td>
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<tr>
<td>Transmission</td>
<td>1,115,762</td>
<td>401,198</td>
<td>1.4%</td>
<td>46-75</td>
<td>622,665</td>
<td>157,397</td>
<td>1.9%</td>
<td>40-75</td>
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<tr>
<td>Distribution</td>
<td>1,297,482</td>
<td>360,257</td>
<td>2.4%</td>
<td>14-70</td>
<td>1,468,481</td>
<td>267,903</td>
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</tr>
<tr>
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<td>249,020</td>
<td>(3,827)</td>
<td>N.M.</td>
<td>N.M.</td>
<td>85,252</td>
<td>(5,743)</td>
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<td>550,952</td>
<td>128,565</td>
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<td>N.M.</td>
<td>244,436</td>
<td>147,587</td>
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<td><strong>Total</strong></td>
<td>$6,747,404</td>
<td>$2,910,638</td>
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<td></td>
<td>$3,687,550</td>
<td>$1,192,130</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>$3,529,524</td>
<td>$2,037,943</td>
<td>2.7%</td>
<td>59-132</td>
<td>$1,110,657</td>
<td>$622,866</td>
<td>2.2%</td>
<td>9-70</td>
</tr>
<tr>
<td>Transmission</td>
<td>1,078,575</td>
<td>394,982</td>
<td>1.7%</td>
<td>46-75</td>
<td>569,746</td>
<td>158,269</td>
<td>1.9%</td>
<td>40-75</td>
</tr>
<tr>
<td>Distribution</td>
<td>1,196,397</td>
<td>361,200</td>
<td>3.2%</td>
<td>14-70</td>
<td>1,337,038</td>
<td>263,561</td>
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<td>473,860</td>
<td>110,796</td>
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<td>237,254</td>
<td>145,541</td>
<td>6.8%</td>
<td>5-35</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$6,400,652</td>
<td>$2,891,320</td>
<td></td>
<td></td>
<td>$3,454,713</td>
<td>$1,182,171</td>
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<tr>
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<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>$152,530</td>
<td>$107,096</td>
<td>N.M.</td>
<td>N.M.</td>
<td>$4,468</td>
<td>-</td>
<td>N.M.</td>
<td>N.M.</td>
</tr>
</tbody>
</table>

N.M. = Not Meaningful
The Registrant Subsidiaries provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. The Registrant Subsidiaries use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. The Registrant Subsidiaries include these costs in the cost of coal charged to fuel expense. The average amortization rate for coal rights and mine development costs related to SWEPCo was $0.26 per ton in 2008 and $0.66 per ton in 2007 and 2006.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

### Asset Retirement Obligations (ARO)

The Registrant Subsidiaries record ARO in accordance with SFAS 143 “Accounting for Asset Retirement Obligations” and FIN 47 “Accounting for Conditional Asset Retirement Obligations” for the retirement of certain ash ponds and coal mining facilities as well as asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property’s use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

As of December 31, 2008 and 2007, I&M’s ARO liability for nuclear decommissioning of the Cook Plant was $891 million and $846 million, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M’s Consolidated Balance Sheets. As of December 31, 2008 and 2007, the fair value of I&M’s assets that are legally restricted for purposes of settling decommissioning liabilities totaled $959 million and $1.1 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M’s Consolidated Balance Sheets.
The following is a reconciliation of the 2008 and 2007 aggregate carrying amounts of ARO by Registrant Subsidiary:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo (a)(d)</td>
<td>$40,019</td>
<td>$2,887</td>
<td>$690</td>
<td>$(3,434)</td>
<td>$11,717</td>
<td>$51,879</td>
</tr>
<tr>
<td>CSPCo (a)(d)</td>
<td>21,658</td>
<td>1,472</td>
<td>-</td>
<td>(2,762)</td>
<td>(2,940)</td>
<td>17,428</td>
</tr>
<tr>
<td>I&amp;M (a)(b)(d)</td>
<td>852,646</td>
<td>45,587</td>
<td>6,120</td>
<td>(548)</td>
<td>(885)</td>
<td>902,920</td>
</tr>
<tr>
<td>OPCo (a)(d)</td>
<td>77,354</td>
<td>5,786</td>
<td>212</td>
<td>(4,148)</td>
<td>10,112</td>
<td>89,316</td>
</tr>
<tr>
<td>PSO (d)</td>
<td>6,521</td>
<td>408</td>
<td>4,264</td>
<td>(369)</td>
<td>4,002</td>
<td>14,826</td>
</tr>
<tr>
<td>SWEPCo (a)(c)(d)(e)</td>
<td>50,262</td>
<td>2,695</td>
<td>9,522</td>
<td>(14,161)</td>
<td>7,023</td>
<td>55,086</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Company</th>
<th>ARO at December 31, 2006</th>
<th>Accretion Expense</th>
<th>Liabilities Incurred</th>
<th>Liabilities Settled</th>
<th>Revisions in Cash Flow Estimates</th>
<th>ARO at December 31, 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo (a)(d)</td>
<td>$37,506</td>
<td>$2,744</td>
<td>-</td>
<td>(2,518)</td>
<td>$2,287</td>
<td>$40,019</td>
</tr>
<tr>
<td>CSPCo (a)(d)</td>
<td>19,603</td>
<td>1,321</td>
<td>-</td>
<td>(2,034)</td>
<td>2,768</td>
<td>21,658</td>
</tr>
<tr>
<td>I&amp;M (a)(b)(d)</td>
<td>809,853</td>
<td>43,254</td>
<td>-</td>
<td>(482)</td>
<td>21</td>
<td>852,646</td>
</tr>
<tr>
<td>OPCo (a)(d)</td>
<td>71,319</td>
<td>5,385</td>
<td>-</td>
<td>(2,542)</td>
<td>3,192</td>
<td>77,354</td>
</tr>
<tr>
<td>PSO (d)</td>
<td>6,437</td>
<td>398</td>
<td>-</td>
<td>(327)</td>
<td>13</td>
<td>6,521</td>
</tr>
<tr>
<td>SWEPCo (a)(c)(d)(e)</td>
<td>48,018</td>
<td>2,961</td>
<td>3,582</td>
<td>(4,579)</td>
<td>280</td>
<td>50,262</td>
</tr>
</tbody>
</table>

(a) Includes ARO related to ash ponds.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant ($891 million and $846 million at December 31, 2008 and 2007, respectively).
(c) Includes ARO related to Sabine Mining Company and Dolet Hills Lignite Company, LLC.
(d) Includes ARO related to asbestos removal.
(e) The current portion of SWEPCo’s ARO, totaling $1.7 million and $434 thousand, at December 31, 2008 and 2007, respectively, is included in Other in the Current Liabilities section of SWEPCo’s Consolidated Balance Sheets.

**Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization**

The amounts of AFUDC included in Allowance For Equity Funds Used During Construction on the Registrant Subsidiaries’ income statements for 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td>(in thousands)</td>
</tr>
<tr>
<td></td>
<td>APCo</td>
<td>8,938</td>
<td>7,337</td>
<td>12,014</td>
</tr>
<tr>
<td></td>
<td>CSPCo</td>
<td>3,364</td>
<td>3,036</td>
<td>1,865</td>
</tr>
<tr>
<td></td>
<td>I&amp;M</td>
<td>965</td>
<td>4,522</td>
<td>7,937</td>
</tr>
<tr>
<td></td>
<td>OPCo</td>
<td>3,073</td>
<td>2,311</td>
<td>2,556</td>
</tr>
<tr>
<td></td>
<td>PSO</td>
<td>1,822</td>
<td>1,367</td>
<td>715</td>
</tr>
<tr>
<td></td>
<td>SWEPCo</td>
<td>14,908</td>
<td>10,243</td>
<td>1,302</td>
</tr>
</tbody>
</table>

The amounts of allowance for borrowed funds used during construction or interest capitalized included in Interest Expense on the Registrant Subsidiaries’ income statements for 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(in thousands)</td>
<td>(in thousands)</td>
<td>(in thousands)</td>
</tr>
<tr>
<td></td>
<td>APCo</td>
<td>9,040</td>
<td>6,962</td>
<td>17,668</td>
</tr>
<tr>
<td></td>
<td>CSPCo</td>
<td>2,677</td>
<td>7,275</td>
<td>5,955</td>
</tr>
<tr>
<td></td>
<td>I&amp;M</td>
<td>4,609</td>
<td>5,315</td>
<td>7,465</td>
</tr>
<tr>
<td></td>
<td>OPCo</td>
<td>25,269</td>
<td>36,641</td>
<td>42,733</td>
</tr>
<tr>
<td></td>
<td>PSO</td>
<td>2,174</td>
<td>5,156</td>
<td>1,491</td>
</tr>
<tr>
<td></td>
<td>SWEPCo</td>
<td>19,800</td>
<td>9,795</td>
<td>2,208</td>
</tr>
</tbody>
</table>
CSPCo, PSO and SWEPCo have generating units that are jointly-owned with affiliated and nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. Each Registrant Subsidiary’s proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Fuel Type</th>
<th>Percent of Ownership</th>
<th>Utility Plant in Service (in thousands)</th>
<th>Construction Work in Progress (i) (in thousands)</th>
<th>Accumulated Depreciation (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSPCo</td>
<td>W.C. Beckjord Generating Station (Unit No. 6) (a)</td>
<td>Coal</td>
<td>12.5%</td>
<td>$ 18,173</td>
<td>$ 1,780</td>
</tr>
<tr>
<td></td>
<td>Conesville Generating Station (Unit No. 4) (b)</td>
<td>Coal</td>
<td>43.5%</td>
<td>85,587</td>
<td>172,619</td>
</tr>
<tr>
<td></td>
<td>J.M. Stuart Generating Station (c)</td>
<td>Coal</td>
<td>26.0%</td>
<td>477,677</td>
<td>23,782</td>
</tr>
<tr>
<td></td>
<td>Wm. H. Zimmer Generating Station (a)</td>
<td>Coal</td>
<td>25.4%</td>
<td>762,353</td>
<td>3,987</td>
</tr>
<tr>
<td></td>
<td>Transmission</td>
<td>N/A</td>
<td>(d)</td>
<td>69,789</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td>$ 1,413,579</td>
<td>$ 202,174</td>
</tr>
<tr>
<td>PSO</td>
<td>Oklaunion Generating Station (Unit No. 1) (e)</td>
<td>Coal</td>
<td>15.6%</td>
<td>$ 88,034</td>
<td>$ 1,739</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>Dolet Hills Generating Station (Unit No. 1) (f)</td>
<td>Lignite</td>
<td>40.2%</td>
<td>$ 255,149</td>
<td>$ 676</td>
</tr>
<tr>
<td></td>
<td>Flint Creek Generating Station (Unit No. 1) (g)</td>
<td>Coal</td>
<td>50.0%</td>
<td>102,777</td>
<td>9,778</td>
</tr>
<tr>
<td></td>
<td>Pirkey Generating Station (Unit No. 1) (g)</td>
<td>Lignite</td>
<td>85.9%</td>
<td>491,071</td>
<td>8,578</td>
</tr>
<tr>
<td></td>
<td>Turk Generating Plant (h)</td>
<td>Coal</td>
<td>73.33%</td>
<td>-</td>
<td>510,279</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td>$ 848,997</td>
<td>$ 529,311</td>
</tr>
</tbody>
</table>

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Operated by PSO and also jointly-owned (54.7%) by TNC.
(f) Operated by Cleco Corporation, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2008, construction costs totaling $34.8 million have been billed to the other owners.
(i) Primarily relates to construction of Turk Generating Plant and environmental upgrades, including the installation of flue gas desulfurization projects at Conesville Generating Station and J. M. Stuart Generating Station.

N/A = Not Applicable
In management’s opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year’s operations because of various factors. The unaudited quarterly financial information for each Registrant Subsidiary is as follows:

<table>
<thead>
<tr>
<th>Quarterly Periods Ended:</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>March 31, 2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$735,027</td>
<td>$541,649</td>
<td>$537,149</td>
<td>$802,188</td>
<td>$336,000</td>
<td>$339,793</td>
</tr>
<tr>
<td>Operating Income</td>
<td>108,465</td>
<td>130,777</td>
<td>98,573</td>
<td>237,438</td>
<td>69,141 (a)</td>
<td>16,820</td>
</tr>
<tr>
<td>Net Income</td>
<td>55,313</td>
<td>76,153</td>
<td>55,258</td>
<td>137,827</td>
<td>37,399 (a)</td>
<td>4,610</td>
</tr>
<tr>
<td>June 30, 2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$667,397</td>
<td>$548,947</td>
<td>$542,647</td>
<td>$782,361</td>
<td>$400,334</td>
<td>$423,617</td>
</tr>
<tr>
<td>Operating Income</td>
<td>62,640</td>
<td>99,034</td>
<td>86,458</td>
<td>109,572</td>
<td>17,017</td>
<td>31,109</td>
</tr>
<tr>
<td>Net Income</td>
<td>26,282</td>
<td>56,393</td>
<td>50,144</td>
<td>52,894</td>
<td>4,127</td>
<td>14,081</td>
</tr>
<tr>
<td>September 30, 2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$798,833</td>
<td>$663,783</td>
<td>$621,023</td>
<td>$857,014</td>
<td>$551,249</td>
<td>$512,463</td>
</tr>
<tr>
<td>Operating Income</td>
<td>82,917</td>
<td>143,456</td>
<td>86,711</td>
<td>121,021</td>
<td>56,157</td>
<td>81,834</td>
</tr>
<tr>
<td>Net Income</td>
<td>39,015</td>
<td>81,662</td>
<td>45,636</td>
<td>56,199</td>
<td>27,744</td>
<td>47,415</td>
</tr>
<tr>
<td>December 31, 2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues (b)</td>
<td>$687,899</td>
<td>$453,722</td>
<td>$465,540</td>
<td>$655,371</td>
<td>$368,362</td>
<td>$278,889</td>
</tr>
<tr>
<td>Operating Income (b)</td>
<td>58,954</td>
<td>50,421</td>
<td>4,356</td>
<td>27,019</td>
<td>18,148</td>
<td>42,882</td>
</tr>
<tr>
<td>Net Income (Loss) (b)</td>
<td>2,253</td>
<td>22,922</td>
<td>(19,163)</td>
<td>(15,797)</td>
<td>9,214</td>
<td>26,648</td>
</tr>
</tbody>
</table>

(a) See “Oklahoma 2007 Ice Storms” section of Note 4 for discussion of the first quarter 2008 reversal of expenses incurred from ice storms in January and December 2007.

(b) See “Allocation of Off-system Sales Margins” section of Note 4 for discussion of the financial statement impact of the FERC’s November 2008 order related to the SIA.

<table>
<thead>
<tr>
<th>Quarterly Periods Ended:</th>
<th>APCo</th>
<th>CSPCo</th>
<th>I&amp;M</th>
<th>OPCo</th>
<th>PSO</th>
<th>SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(in thousands)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>March 31, 2007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$665,728</td>
<td>$447,912</td>
<td>$492,869</td>
<td>$679,441</td>
<td>$315,313</td>
<td>$344,099</td>
</tr>
<tr>
<td>Operating Income (Loss)</td>
<td>137,174</td>
<td>82,596</td>
<td>63,835</td>
<td>140,532</td>
<td>(25,187)(c)</td>
<td>26,462</td>
</tr>
<tr>
<td>Net Income (Loss)</td>
<td>70,227</td>
<td>46,981</td>
<td>29,463</td>
<td>79,261</td>
<td>(20,426)(c)</td>
<td>9,605</td>
</tr>
<tr>
<td>June 30, 2007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$557,410</td>
<td>$506,022</td>
<td>$465,540</td>
<td>$655,371</td>
<td>$321,639</td>
<td>$346,022</td>
</tr>
<tr>
<td>Operating Income</td>
<td>33,844</td>
<td>134,576</td>
<td>64,122</td>
<td>140,294</td>
<td>21,478</td>
<td>14,940</td>
</tr>
<tr>
<td>Income Before Extraordinary Loss</td>
<td>3,281</td>
<td>80,022</td>
<td>30,035</td>
<td>74,340</td>
<td>6,295</td>
<td>1,624</td>
</tr>
<tr>
<td>Extraordinary Loss – Reapplication of Regulatory Accounting for Generation, Net of Tax</td>
<td>(78,763)(d)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Net Income (Loss)</td>
<td>(75,482)</td>
<td>80,022</td>
<td>30,035</td>
<td>74,340</td>
<td>6,295</td>
<td>1,624</td>
</tr>
<tr>
<td>September 30, 2007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$706,576</td>
<td>$607,141</td>
<td>$559,176</td>
<td>$757,743</td>
<td>$448,036</td>
<td>$448,510</td>
</tr>
<tr>
<td>Operating Income</td>
<td>67,833</td>
<td>149,730</td>
<td>89,156</td>
<td>146,689</td>
<td>70,670</td>
<td>76,617</td>
</tr>
<tr>
<td>Net Income</td>
<td>24,058</td>
<td>85,454</td>
<td>49,124</td>
<td>75,262</td>
<td>36,571</td>
<td>44,120</td>
</tr>
<tr>
<td>December 31, 2007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$677,555</td>
<td>$482,237</td>
<td>$505,110</td>
<td>$706,095</td>
<td>$310,562</td>
<td>$344,831</td>
</tr>
<tr>
<td>Operating Income (Loss)</td>
<td>81,975</td>
<td>80,454</td>
<td>60,053</td>
<td>98,837</td>
<td>(71,796)(c)</td>
<td>16,683</td>
</tr>
<tr>
<td>Net Income (Loss)</td>
<td>35,933</td>
<td>45,631</td>
<td>28,273</td>
<td>39,701</td>
<td>(46,564)(c)</td>
<td>10,915</td>
</tr>
</tbody>
</table>

(c) See “Oklahoma 2007 Ice Storms” section of Note 4 for discussion of expenses incurred from ice storms in January and December 2007.

(d) See “Virginia Restructuring” in “Extraordinary Item” section of Note 2 for discussion of the extraordinary loss booked in the second quarter of 2007.
OUTLOOK FOR 2009

Market Impacts

In 2008, the domestic and world economies experienced significant slowdowns. Concurrently, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting the Registrant Subsidiaries’ access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications since the Registrant Subsidiaries rely on continuing access to capital to fund operations and capital expenditures.

The current credit markets are constraining the Registrant Subsidiaries’ ability to issue new debt and refinance existing debt. APCo, OPCo and PSO have $150 million, $78 million and $50 million, respectively, maturing in 2009. Management intends to refinance these maturities. To support operations, AEP has $3.9 billion in aggregate credit facility commitments. These commitments include 27 different banks with no one bank having more than 10% of the total bank commitments. Short-term funding for the Registrant Subsidiaries comes from AEP’s credit facilities which support the Utility Money Pool. In 2008, AEP borrowed $2 billion under the credit facilities to enhance its position during this period of market disruptions. This money can be loaned to the Registrant Subsidiaries through the Utility Money Pool.

Management cannot predict the length of time the current credit situation will continue or its impact on future operations and the Registrant Subsidiaries’ ability to issue debt at reasonable interest rates. When market conditions improve, management plans to repay the amounts drawn under the credit facilities and issue commercial paper and long-term debt. If there is not an improvement in access to capital, management believes that the Registrant Subsidiaries have adequate liquidity, through the Utility Money Pool and cash flows from their operations to support planned business operations and capital expenditures through 2009.

AEP has significant investments in several trust funds to provide for future payments of pensions and OPEB. I&M has significant investments in several trust funds to provide for future payments of nuclear decommissioning and spent nuclear fuel disposal. Although all of the trust funds’ investments are well-diversified and managed in compliance with all laws and regulations, the value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds’ ability to make their required payments.

On behalf of the Registrant Subsidiaries, AEPSC enters into risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. AEP’s risk management organization monitors these exposures on a daily basis to limit the Registrant Subsidiaries’ economic and financial statement impact on a counterparty basis.

Economic Slowdown

Following the indications of a slowing economy in 2007, the U.S. economy experienced what some have labeled a financial crisis in 2008. These economic troubles impacted and will continue to impact residential, commercial and industrial sales as well as sales opportunities in the wholesale market. Most sections of the Registrant Subsidiaries’ service territories are experiencing slowdowns in new construction, resulting in residential and commercial customer base growing at a decreased rate. Starting in the fourth quarter of 2008, various sections of the Registrant Subsidiaries’ service territories also experienced decreases in industrial sales due to temporary shutdowns and reduced shifts by some of the large industrial customers. Management expects these trends to continue throughout 2009.

In February 2009, Century Aluminum, a major industrial customer (325 MW load) of APCo, announced the curtailment of operations at its Ravenswood, WV facility.
**Budgeted Construction Expenditures**

Budgeted construction expenditures for the Registrant Subsidiaries for 2009 are:

<table>
<thead>
<tr>
<th>Company</th>
<th>Budgeted Construction Expenditures (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$367.5</td>
</tr>
<tr>
<td>CSPCo</td>
<td>269.6</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>361.6</td>
</tr>
<tr>
<td>OPCo</td>
<td>439.4</td>
</tr>
<tr>
<td>PSO</td>
<td>187.7</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>457.4</td>
</tr>
</tbody>
</table>

Budgeted construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

**LIQUIDITY**

**Sources of Funding**

Short-term funding for the Registrant Subsidiaries comes from AEP’s commercial paper program and revolving credit facilities through the Utility Money Pool. AEP and its Registrant Subsidiaries also operate a money pool to minimize the AEP System’s external short-term funding requirements and sell accounts receivable to provide liquidity. The credit facilities that support the Utility Money Pool were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $46 million following its bankruptcy. In March 2008, these credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit (LOC). The Registrant Subsidiaries generally use short-term funding sources (the Utility Money Pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leasebacks, leasing arrangements and additional capital contributions from AEP.

In April 2008, the Registrant Subsidiaries and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.’s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. The Registrant Subsidiaries may issue LOCs under the credit facilities. Each subsidiary has a borrowing/LOC limit under the credit facilities. As of December 31, 2008, a total of $372 million of LOCs were issued under the 3-year credit agreement to support variable rate demand notes. The following table shows each Registrant Subsidiaries’ borrowing/LOC limit under each credit facility and the outstanding amount of LOCs for the $650 million facility.

<table>
<thead>
<tr>
<th>Company</th>
<th>$650 million Credit Facility Borrowing/LOC Limit (in millions)</th>
<th>$350 million Credit Facility Borrowing/LOC Limit (in millions)</th>
<th>LOC Amount Outstanding Against $650 million Agreement at December 31, 2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$300</td>
<td>$150</td>
<td>$127</td>
</tr>
<tr>
<td>CSPCo</td>
<td>230</td>
<td>120</td>
<td>-</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>230</td>
<td>120</td>
<td>78</td>
</tr>
<tr>
<td>OPCo</td>
<td>400</td>
<td>200</td>
<td>167</td>
</tr>
<tr>
<td>PSO</td>
<td>65</td>
<td>35</td>
<td>-</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>230</td>
<td>120</td>
<td>-</td>
</tr>
</tbody>
</table>

At December 31, 2008, there were no outstanding amounts under the $350 million facility.
Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.

Sale of Receivables Through AEP Credit

In 2008, AEP Credit renewed its sale of receivables agreement through October 2009. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Management intends to extend or replace the sale of receivables agreement. At December 31, 2008, $650 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit purchases accounts receivable from the Registrant Subsidiaries.

SIGNIFICANT FACTORS

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amended the restructuring law effective July 31, 2008 and required electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities could include a fuel cost recovery mechanism (FCR) in their ESP filing. Electric utilities also had an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, would have transitioned CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve and/or modify each utility’s ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than an MRO. Both alternatives involve a “significantly excessive earnings” test (SEET) based on what public companies, including other utilities with similar risk profiles, earn on equity.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo’s and OPCo’s ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a FCR that primarily includes fuel costs, purchased power costs, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The FCR is proposed to be phased into customer bills over the three-year period from 2009 through 2011 and recovered with a weighted average cost of capital carrying cost deferral over seven years from 2012 through 2018. If the ESPs are approved as filed, effective with the implementation of the ESPs, CSPCo and OPCo will defer fuel cost over/under-recoveries and related carrying costs, including amounts unrecovered through the phase in period, for future recovery.

In addition to the FCR, the requested ESP increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include recovery for programs for smart metering initiatives, economic development, mandated energy efficiency, renewable resources and peak demand reduction programs.

Within the ESP requests, CSPCo and OPCo would also recover existing regulatory assets of $47 million and $39 million, respectively, for customer choice implementation and line extension carrying costs incurred through December 2008. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $31 million and $23 million, respectively, through December 2008. The PUCO had previously issued orders allowing deferral of these costs. Such costs would be recovered over an 8-year period beginning January 2011. If the PUCO does not approve recovery of these regulatory assets in this or some future proceeding, it would have an adverse effect on future net income and cash flows.

Hearings were held in November and December 2008. Many intervenors filed opposing testimony. CSPCo and OPCo requested retroactive application of the new rates, including the FCR, back to the start of the January 2009 billing cycle upon approval of the ESPs. The RSP rates were effective for the years ended December 31, 2006, 2007 and 2008 under which CSPCo and OPCo had three annual generation rate increases of 3% and 7%, respectively. The RSP also allowed additional annual generation rate increases of up to an average of 4% per year to recover new
governmentally-mandated costs. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. A motion to dismiss the application has been filed by Ohio Partners for Affordable Energy, while the Ohio Consumers’ Counsel has filed comments opposing the application. The PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO issues a ruling on the ESPs or the end of the March 2009 billing cycle, whichever comes first. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs. CSPCo and OPCo anticipate a final order from the PUCO during the first quarter of 2009.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor’s warranty, insurance and the regulatory process. Management’s current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. In January 2009, I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the fuel cost forecast period of April through September 2009. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

New Generation

In 2008, AEP completed or is in various stages of construction of the following generation facilities:

<table>
<thead>
<tr>
<th>Operating Company</th>
<th>Project Name</th>
<th>Location</th>
<th>Total Projected Cost (a) (in millions)</th>
<th>CWIP (b) (in millions)</th>
<th>Fuel Type</th>
<th>Plant Type</th>
<th>Nominal MW Capacity</th>
<th>Commercial Operation Date (Projected)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>Southwestern (c) Oklahoma</td>
<td>$56</td>
<td>$ -</td>
<td>Gas</td>
<td>Simple-cycle</td>
<td>150</td>
<td>2008</td>
<td></td>
</tr>
<tr>
<td>PSO</td>
<td>Riverside (d) Oklahoma</td>
<td>$58</td>
<td>$ -</td>
<td>Gas</td>
<td>Simple-cycle</td>
<td>150</td>
<td>2008</td>
<td></td>
</tr>
<tr>
<td>AEGCo</td>
<td>Dresden (e) Ohio</td>
<td>$310(e)</td>
<td>$179</td>
<td>Gas</td>
<td>Combined-cycle</td>
<td>580</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>SWEPco</td>
<td>Stall Louisiana</td>
<td>$384</td>
<td>$252</td>
<td>Gas</td>
<td>Combined-cycle</td>
<td>500</td>
<td>2010</td>
<td></td>
</tr>
<tr>
<td>SWEPco</td>
<td>Turk (f) Arkansas</td>
<td>$1,628(f)</td>
<td>$510</td>
<td>Coal</td>
<td>Ultra-supercritical</td>
<td>600(f)</td>
<td>2012</td>
<td></td>
</tr>
<tr>
<td>APCo</td>
<td>Mountaineer (g) West Virginia</td>
<td>(g)</td>
<td>(g)</td>
<td>Coal</td>
<td>IGCC</td>
<td>629</td>
<td>(g)</td>
<td></td>
</tr>
<tr>
<td>CSPCo/OPCo</td>
<td>Great Bend (g) Ohio</td>
<td>(g)</td>
<td>(g)</td>
<td>Coal</td>
<td>IGCC</td>
<td>629</td>
<td>(g)</td>
<td></td>
</tr>
</tbody>
</table>

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(e) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the “Total Projected Cost” section above.
(f) SWEPo plans to own approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See “Turb Plant” section below.
(g) Construction of IGCC plants are pending regulatory approvals. See “IGCC Plants” section below.
In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC, (b) capping CO₂ emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT’s order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT’s grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In November 2008, SWEPCo received the air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant’s permit is heard. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit.

In January 2008 and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor’s Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission’s final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission’s report, it could impact SWEPCo’s proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits to build the Turk Plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of December 31, 2008, SWEPCo has capitalized approximately $510 million of expenditures (including AFUDC) and has significant contractual construction commitments for an additional $727 million. As of December 31, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.
**IGCC Plant**

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying APCo’s request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through December 31, 2008, APCo deferred for future recovery preconstruction IGCC costs of $20 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers’ Counsel filed a motion with the PUCO requesting all Phase 1 cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers’ Counsel’s motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

**Pension and Postretirement Benefit Plans**

AEP maintains qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plans (collectively the Pension Plans). AEP merged the Qualified Plans at December 31, 2008. Additionally, AEP entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the nonqualified, supplemental plans. AEP also sponsors other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

The following table shows the net periodic benefit cost and assumed rate of return on the Plans’ assets:

<table>
<thead>
<tr>
<th>Years Ended December 31,</th>
<th>2008 (in millions)</th>
<th>2007 (in millions)</th>
<th>2006 (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Periodic Benefit Cost</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pension Plans</td>
<td>$51</td>
<td>$50</td>
<td>$71</td>
</tr>
<tr>
<td>Postretirement Plans</td>
<td>80</td>
<td>81</td>
<td>96</td>
</tr>
<tr>
<td><strong>Assumed Rate of Return</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pension Plans</td>
<td>8.00%</td>
<td>8.50%</td>
<td>8.50%</td>
</tr>
<tr>
<td>Postretirement Plans</td>
<td>8.00%</td>
<td>8.00%</td>
<td>8.00%</td>
</tr>
</tbody>
</table>

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans’ assets. In developing the expected long-term rate of return assumption for 2009, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. AEP also considered historical returns of the investment markets as well as its ten-year average return, for the period ended December 2008, of approximately 3%. AEP anticipates that the investment managers employed for the Plans will generate future returns averaging 8.00% for the Pension Plan and 7.75% for the Postretirement Plans.
The expected long-term rate of return on the Plans’ assets is based on AEP’s targeted asset allocation and expected investment returns for each investment category. The investment returns for the Postretirement Plans are assumed to be slightly less than those of the Pension Plans as a portion of the returns for the Postretirement Plans is taxable. AEP’s assumptions are summarized in the following table:

<table>
<thead>
<tr>
<th></th>
<th>Pension Plans</th>
<th>Other Postretirement Benefit Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
<td>2009</td>
</tr>
<tr>
<td></td>
<td>Actual</td>
<td>Target</td>
</tr>
<tr>
<td>Asset Allocation</td>
<td>Long-term</td>
<td>Rate of Return</td>
</tr>
<tr>
<td>Equity</td>
<td>Equity</td>
<td>47%</td>
</tr>
<tr>
<td></td>
<td>Allocation</td>
<td>55%</td>
</tr>
<tr>
<td></td>
<td>9.5%</td>
<td></td>
</tr>
<tr>
<td>Real Estate</td>
<td>Real Estate</td>
<td>6%</td>
</tr>
<tr>
<td></td>
<td>Allocation</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>7.5%</td>
<td></td>
</tr>
<tr>
<td>Debt Securities</td>
<td>Debt Securities</td>
<td>42%</td>
</tr>
<tr>
<td></td>
<td>Allocation</td>
<td>39%</td>
</tr>
<tr>
<td></td>
<td>6.0%</td>
<td></td>
</tr>
<tr>
<td>Cash and Cash Equivalents</td>
<td>Cash and Cash Equivalents</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>Allocation</td>
<td>1%</td>
</tr>
<tr>
<td></td>
<td>3.5%</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>Total</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall Expected Return</td>
<td></td>
<td>8.00%</td>
</tr>
</tbody>
</table>

Global capital markets experienced extreme volatility in 2008. The value of investments in AEP’s pension and OPEB trusts declined substantially due to decreases in domestic and international equity markets. Although the asset values are currently lower, this decline has not affected the funds’ ability to make their required payments.

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. AEP believes that 8% for the Pension Plans and 7.75% for the Postretirement Plans are reasonable long-term rate of return on the Plans’ assets despite the recent market volatility. The Pension Plans’ assets had an actual (loss) gain of (24.1)% and 9.2% for the years ended December 31, 2008 and 2007, respectively. The Postretirement Plans’ assets had an actual (loss) gain of (24.7)% and 8.6% for the years ended December 31, 2008 and 2007, respectively. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2008, AEP had cumulative losses of approximately $1 billion that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, “Employers’ Accounting for Pensions.”

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody’s Aa bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2008 under this method was 6.00% for the Pension Plans and 6.10% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans’ assets of 8.00%, a discount rate of 6.00% and various other assumptions, AEP estimates that the pension costs for all pension plans will approximate $92 million, $145 million and $152 million in 2009, 2010 and 2011, respectively. Based on an expected rate of return on the OPEB plans’ assets of 7.75%, a discount rate of 6.10% and various other assumptions, AEP estimates Postretirement Plan costs will approximate $148 million, $140 million and $121 million in 2009, 2010 and 2011, respectively. Future actual cost will depend on future investment performance,
changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in “Pension and Other Postretirement Benefits” within the “Critical Accounting Estimates” section of this Combined Management’s Discussion and Analysis of Registrant Subsidiaries.

The value of AEP’s Pension Plans’ assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007 primarily due to investment losses. The Qualified Plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of AEP’s Postretirement Plans’ assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007 primarily due to investment losses. The Postretirement Plans paid $120 million in benefits to plan participants during 2008.

Investments in trusts are stated at fair market value. AEP utilizes the trustee’s external pricing service to measure the market value of the underlying investments. AEP’s investment managers review and validate the prices utilized to determine fair market value. AEP also performs valuation testing to validate the market values of the actively traded securities. AEP receives audit reports of the trustee’s operating controls and valuation processes. Where possible, quoted prices on actively traded exchanges are used to determine value. Debt holdings that are not actively traded may be valued based on the observable pricing of comparable securities. Investments in commingled funds are generally not actively traded and are priced at a Net Asset Value (NAV) which is based on the underlying holdings of the funds. These holdings are typically actively traded equities or debt securities that may be valued in a manner similar to direct debt investments. Trust assets as of December 31, 2008 include approximately $244 million of real estate and private equity investments in the pension fund that are valued based on methods requiring judgment.

AEP’s Qualified Plans were underfunded as of December 31, 2008. No contribution to the Qualified Plans is required under ERISA in 2009. Minimum contributions to the Qualified Plans of $365 million in 2010 and $258 million in 2011 are currently projected under ERISA and may vary significantly based on future market returns, changes in actuarial assumptions and other factors. AEP’s nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation exceeded plan assets by $80 million and $77 million at December 31, 2008 and 2007, respectively.

Certain pension plans AEP sponsors contain a cash balance benefit feature. In 2008, the IRS issued Determination Letters confirming the tax exempt status of these plans including the cash balance benefit feature.

The Worker, Retiree and Employer Recovery Act of 2008 did not materially impact the plans.

**Litigation**

**Environmental Litigation**

**New Source Review (NSR) Litigation:** The Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. In 2007, the U.S. District Court for the Southern District of Ohio approved the AEP System’s consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, AEP’s management agreed to annual SO2 and NOx emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. AEP’s management agreed to install FGD equipment at KPCo’s Big Sandy Plant and at OPCo’s Muskingum River Plant no later than the end of 2015. AEGCo and I&M agreed to install SCR and FGD emissions control equipment on their jointly-owned Rockport Plant no later than the end of 2017 for Unit 1 and no later than the end of 2019 for Unit 2. APCo agreed to install selective non-catalytic reduction, a NOx-reduction technology, no later than the end of 2009 at Clinch River Plant.

CSPCo jointly-owns Beckjord and Stuart Stations with Duke Energy Ohio, Inc. and Dayton Power and Light Company. A jury trial returned a verdict of no liability at the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. In October 2008, the court approved a settlement in a citizen suit action filed by Sierra Club against the jointly-owned units at Stuart Station. Under the settlement, the joint-owners of Stuart Station agreed to certain emission targets related to NOx, SO2 and PM. The joint-owners also
agreed to make energy efficiency and renewable energy commitments that are conditioned on PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO₂ allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and financial condition.

Environmental Matters

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the CAA to reduce emissions of SO₂, NOₓ and PM from fossil fuel-fired power plants and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain power plants.

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of I&M’s nuclear units. Management also monitors possible future requirements to reduce CO₂ and other greenhouse gases (GHG) emissions to address concerns about global climate change. All of these matters are discussed below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation’s air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

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

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and PM₂.₅. These new standards could increase the levels of SO₂ and NOₓ reductions required from the Registrant Subsidiaries’ facilities. The Federal EPA also established a lower standard for lead, and conducts periodic reviews for additional criteria pollutants including SO₂ and NOₓ.

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR). It requires specific reductions in SO₂ and NOₓ emissions from power plants and assists states developing new SIPs to meet the NAAQS. CAIR reduces regional emissions of SO₂ and NOₓ (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO₂ by 50% by 2010, and by 65% by 2015. NOₓ emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reductions of both SO₂ and
NOx would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate CAIR and remanded the rule to the Federal EPA. In September 2008, the Federal EPA and other parties petitioned for rehearing. In December 2008, the D.C. Circuit Court of Appeals granted the Federal EPA’s petition and remanded the rule to the Federal EPA without vacatur, allowing CAIR to remain in effect while a new rulemaking is conducted. Management is unable to predict how the Federal EPA will respond to the remand. States were required to develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which the Registrant Subsidiaries’ power plants are located will be covered by CAIR and have or are developing CAIR SIPs. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals. The Federal EPA or the states may elect to seek further reductions of SO2 and NOx in response to more stringent PM and ozone NAAQS.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO2 and NOx emissions in order to comply with CAIR. States were required to develop and submit their SIPs to implement CAMR by November 2006.

Various states and special interest groups challenged the rule in the D.C. Circuit Court of Appeals. The court ruled that the Federal EPA’s action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA, and vacated and remanded the federal rules for both new and existing coal-fired power plants to the Federal EPA. The Federal EPA filed a petition for review by the U.S. Supreme Court, but the new Federal EPA Administrator asked that the petition be withdrawn. Management is unable to predict the outcome of this appeal or how the Federal EPA will respond to the remand.

The Acid Rain Program: The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO2 emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. The Registrant Subsidiaries continue to meet their obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. CAIR currently uses the SO2 allowances originally allocated through the Acid Rain Program as the basis for its SO2 cap-and-trade system. Management is unable to predict if or how any replacement for CAIR will utilize the SO2 allowances from the Acid Rain Program.

Regional Haze: The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (Regional Haze program). In 2005, the Federal EPA issued its Clean Air Visibility Rule (CAVR), detailing how the CAA’s best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that CAIR will result in more visibility improvements than BART for power plants subject to it. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states (Oklahoma, Texas and Arkansas of the AEP System) not subject to CAIR requirements for SO2 and NOx, some additional controls will be required. The courts upheld the final rule.

In January 2009, the Federal EPA issued a determination that 37 states (including Indiana, Ohio, Oklahoma, Texas and Virginia) failed to submit SIP’s fulfilling the Regional Haze program requirements by the deadline, and commencing a 2-year period for the development of a Federal Implementation Plan (FIP) in these states. Management is unable to predict if or how the remand of CAIR or the development of a FIP for certain states may affect compliance obligations for the Regional Haze programs.
Estimated Air Quality Environmental Investments

The CAIR and the consent decree signed to settle the NSR litigation require significant additional investments, some of which are estimable. Management’s estimates are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and selected compliance alternatives and their costs. In short, management cannot estimate compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

By the end of 2008, APCo, CSPCo and OPCo installed SCR technology on a total of 10,580 MW at their power plants to comply with NO\textsubscript{x} requirements. The Registrant Subsidiaries comply with SO\textsubscript{2} requirements by installing scrubbers and using alternate fuels and SO\textsubscript{2} allowances. The Registrant Subsidiaries receive allowances through allocation and purchase at either the annual Federal EPA auction or in the market. Decreasing allowance allocations, diminishing SO\textsubscript{2} allowance banks, increasing allowance costs, CAIR and commitments in the consent decree will require installation of additional controls on the Registrant Subsidiaries’ power plants through 2019. The Registrant Subsidiaries plan to install additional scrubbers on 8,200 MW for SO\textsubscript{2} control. This amount includes the installation of scrubbers on the Rockport Plant which is 50% owned by I&M and 50% owned by AEGCo. From 2009 to 2013, the following table shows the total estimated costs for environmental investment and additional scrubbers and other SO\textsubscript{2} equipment by Registrant Subsidiary:

<table>
<thead>
<tr>
<th>Company</th>
<th>Total Environmental Cost (in millions)</th>
<th>Cost of Additional Scrubbers and SO\textsubscript{2} Equipment (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$386.4</td>
<td>$172.9</td>
</tr>
<tr>
<td>CSPCo</td>
<td>367.5</td>
<td>103.5</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>48.4</td>
<td>1.0</td>
</tr>
<tr>
<td>OPCo</td>
<td>610.7</td>
<td>271.0</td>
</tr>
<tr>
<td>PSO</td>
<td>807.4</td>
<td>787.5</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>672.6</td>
<td>666.4</td>
</tr>
</tbody>
</table>

These estimates may be revised as a result of the court’s decision remanding the CAIR and CAMR. The Registrant Subsidiaries will also incur additional operation and maintenance expenses in future years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Due to CAIR and the NSR settlement discussed above, the Registrant Subsidiaries expect to incur additional costs for pollution control technology retrofits between 2014 and 2020 totaling approximately $3.3 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states’ implementation of these regulatory programs, including the potential for SIPs and FIPs that impose standards more stringent than CAIR; (2) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR; (3) the actual performance of the pollution control technologies installed on each unit; (4) changes in costs for new pollution controls; (5) new generating technology developments; and (6) other factors. Associated operational and maintenance expenses will also increase during those years. Management cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

The Registrant Subsidiaries will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through regulated rates (in regulated jurisdictions). The Registrant Subsidiaries should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future net income, cash flows and possibly financial condition.
Clean Water Act Regulation

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant’s cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. Management expected additional capital and operating expenses, which the Federal EPA estimated could be $193 million for the Registrant Subsidiaries’ plants. The Registrant Subsidiaries undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates. The following table shows the investment amount per Registrant Subsidiary:

<table>
<thead>
<tr>
<th>Company</th>
<th>Estimated Compliance Investments (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APCo</td>
<td>$21</td>
</tr>
<tr>
<td>CSPCo</td>
<td>19</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>118</td>
</tr>
<tr>
<td>OPCo</td>
<td>31</td>
</tr>
</tbody>
</table>

In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. Management cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. The Registrant Subsidiaries sought further review and filed for relief from the schedules included in their permits.

In April 2008, the U.S. Supreme Court agreed to review decisions from the Second Circuit Court of Appeals that limit the Federal EPA’s ability to weigh the retrofitting costs against environmental benefits. Management is unable to predict the outcome of this appeal.

Potential Regulation of CO₂ and Other GHG Emissions

The scientific community, led largely by the Intergovernmental Panel on Climate Change, has provided scientific evidence that human activity, and particularly the combustion of fossil fuels, has increased the levels of GHG in the atmosphere and contributed to observed changes in the global climate system. These findings have led to proposals for substantial transformation of the world’s energy production and transportation systems in order to slow, and ultimately reduce, the production of CO₂ and other GHG emissions sufficiently to reduce atmospheric concentrations. Because approximately 90% of the electricity generated by the AEP System is produced by the combustion of fossil fuels, AEP’s management is helping to lead the discussion nationally and internationally to find a reasonable, achievable approach and enact federal energy policy that is realistic in time frame and does not seriously harm the U.S. economy. The AEP System is also developing advanced coal technologies so that coal can continue to be the important energy resource it is today. The AEP System supports the adoption of an economy-wide, cap-and-trade GHG reduction program that allows electric companies to provide reliable, reasonably priced electricity to customers and that fosters the international participation that is necessary to make meaningful progress.

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in GHG emissions. The U.S. signed the Kyoto Protocol in 1998, but the treaty was not submitted to the Senate for its consent. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. The first commitment period under the Kyoto Protocol ends in 2012. Negotiations designed to lead to a global agreement on limiting GHG emissions after the Kyoto Protocol expires have commenced, and are focused on flexible mechanisms that can address the concerns expressed by the U.S. and others regarding the global impacts of increasing emissions in developing economies, including China, Brazil, and India, and mitigating the economic impacts of GHG reductions in developed countries given current economic conditions.
Since 2005, several members of Congress have introduced bills that would regulate GHG emissions, including emissions from power plants. Congress has passed no legislation, but recent bills have received more serious consideration and some form of national legislation impacting the electric utility industry is likely to pass within the next few years. Such legislation is likely to take the form of direct regulation of GHG emissions through cap-and-trade provisions. In addition and related to climate change legislation, a national renewable portfolio standard, energy efficiency requirements for electric utilities and other measures may pass Congress in the next few years.

Several states have adopted programs that directly regulate GHG emissions from power plants, but none of these programs are currently in effect in states where the AEP System has generating facilities. Certain of the states where the Registrant Subsidiaries operate have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). The Registrant Subsidiaries are taking steps to comply with these requirements. Through recent purchases of wind power and the existing wind assets that the AEP System has developed and future plans, the integrated resource plan contains a 10% renewable energy target by 2020, which is nearly double the level of renewable energy requirements in effect in those states. Management’s plans are based on the reasonable expectation that additional federal or state requirements may be enacted that will affect the AEP System.

AEP’s management supports a reasonable approach to GHG emission reductions, including a mandate to achieve economy-wide reductions that recognizes a reliable and affordable electric supply is vital to economic stability. The AEP System has taken measurable, voluntary actions to reduce and offset its GHG emissions. The AEP System participates in a number of voluntary programs to monitor, mitigate and reduce GHG emissions, including the Federal EPA’s Climate Leaders program, the DOE’s GHG reporting program and the Chicago Climate Exchange. Through the end of 2007, the AEP System reduced emissions by a cumulative 46 million metric tons from adjusted baseline levels in 1998-2001 as a result of these voluntary actions. The AEP System’s total GHG emissions in 2007 were 155.8 million metric tons. AEP’s management estimates that 2008 emission will be approximately 155 million metric tons and the cumulative reductions will be in excess of 51 metric million tons.

AEP’s management believes that climate change is a global issue and that the United States should assume 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. AEP’s management, along with the International Brotherhood of Electrical Workers (IBEW), proposed that a consistent national policy for reasonable GHG controls should include the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy GHG reduction technologies
- Removal of regulatory or economic barriers to GHG emission reductions
- Recognition for early actions/investments in GHG reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

In July 2007, AEP, along with several other utilities and labor unions, including the IBEW, announced support for the Low Carbon Economy Act of 2007. This legislation requires GHG reductions beginning in 2012 through an economy-wide cap-and-trade program. It contemplates reducing GHG emissions to their 2006 levels by 2020, and to their 1990 levels by 2030. Allowances to emit GHG would be allocated, auctioned or a combination of each, including a safety valve allowance price of $12 per metric ton, subject to increasing adjustments. The legislation also includes incentives for other nations to adopt measures to limit GHG emissions. AEP’s management endorses this legislation because it sets reasonable and achievable reduction targets and includes key elements of the AEP-IBEW principles. AEP’s management also supports the Edison Electric Institute (EEI) principles for federal climate change legislation, including the consensus approach developed by EEI for the allocation of emission allowances.
President Obama has stated that he favors climate legislation that would reduce GHG emissions by 80% by 2050 and require the auctioning of all allowances. AEP’s management opposes a 100% auction of GHG emission allowances, as it would substantially increase the costs of compliance on the AEP System and increase customer rates. AEP’s management supports reasonable emission reduction targets that allow sufficient time for technology development and recognize that commercial scale technologies to provide substantial GHG emission reductions at new or existing electric generating units are not currently available.

While comprehensive economy-wide regulation of GHG emissions might be achieved through new legislation, several states and interest groups petitioned the Federal EPA to establish GHG emission standards under the existing requirements of the CAA. In April 2007, the U.S. Supreme Court reversed and remanded the Federal EPA’s determination that it lacked the authority to regulate GHG emissions from motor vehicles for purposes of climate change under the CAA. In response to the Supreme Court’s decision, the Federal EPA issued an Advance Notice of Proposed Rulemaking in July 2008 seeking comment on its analysis of the applicability of various provisions of the CAA, and the suitability of different provisions of the mobile source, stationary source, and permitting programs under the CAA to effectively regulate GHG emissions. AEP’s management agrees with the assessment of the previous EPA Administrator that the existing authorities under the CAA are not well-suited to achieving economy-wide cost-effective reductions of GHG emissions. Shortly after taking office, President Obama directed the Federal EPA to re-examine a decision denying the request by the State of California for a waiver that would allow states to establish higher fuel efficiency standards as a means of reducing GHG emissions from mobile sources. Thirteen states have taken action that would implement the California standards if the Federal EPA issues such a waiver. While this waiver, if issued, would have no immediate impact on stationary sources, should the Federal EPA choose to take other actions to regulate GHG emissions under the CAA, they could have a material impact upon the costs of operating fossil-fueled generating plants.

In addition, certain groups have filed lawsuits alleging that emissions of CO₂ and other GHGs are a “public nuisance” and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. AEP and certain of its subsidiaries have been named in two pending lawsuits, which AEP’s management is vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on operations or financial condition. See “Carbon Dioxide Public Nuisance Claims” and “Alaskan Villages’ Claims” sections of Note 6.

AEP’s management expects that GHG emissions, including those associated with the operation of fossil-fueled generating plants, will be limited by law or regulation in the future. The manner or timing of any such limitations cannot be predicted. While the AEP System is exploring a number of alternatives, including the capture and storage of GHG emissions from new and existing power generation facilities, there is currently no demonstrated technology that controls the emissions of GHG from fossil-fueled generating plants. The AEP System is advancing more efficient technologies for power generation, including ultra-super-critical technology and IGCC, as authorized by the regulatory commissions. Carbon capture and storage or other GHG limiting technology, if successfully demonstrated, is likely to have a material impact on the cost of operating fossil-fueled generating plants. The AEP System is also pursuing renewable sources of energy generation, energy efficiency measures, gridSMART load management investments and other improved transmission, distribution and energy storage methods to reduce overall GHG emissions from its operations. The Registrant Subsidiaries will seek recovery of the costs from customers through regulated rates and market prices of electricity.

Other Environmental Concerns

Management performs environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, the Registrant Subsidiaries manage other environmental concerns that are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on net income, cash flows and possibly financial condition.
Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP’s Board of Directors and the Audit Committee reviews the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about the Registrant Subsidiaries’ most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required: The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (APCo, I&M, PSO and a portion of CSPCo, OPCo and SWEPCo) reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrant Subsidiaries recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the Registrant Subsidiaries match the timing of expense recognition with the recovery of such expense in regulated revenues. Likewise, they match income with the regulated revenues from their customers in the same accounting period. Regulatory liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used: When incurred costs are probable of recovery through regulated rates, the Registrant Subsidiaries record them as regulatory assets on the balance sheet. Regulatory assets are reviewed for probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate of return earned on invested capital and the timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on net income. Refer to Note 5 of the Notes to Financial Statements of Registrant Subsidiaries for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required: The Registrant Subsidiaries record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.
The change in unbilled electric utility revenues included in Revenue for the years ended December 31, 2008, 2007 and 2006 were as follows:

<table>
<thead>
<tr>
<th>Company</th>
<th>Years Ended December 31, (in thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2008</td>
</tr>
<tr>
<td>APCo</td>
<td>$32,815</td>
</tr>
<tr>
<td>CSPCo</td>
<td>7,614</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>12,934</td>
</tr>
<tr>
<td>OPCo</td>
<td>4,048</td>
</tr>
<tr>
<td>PSO</td>
<td>(211)</td>
</tr>
<tr>
<td>SWEPCo</td>
<td>5,008</td>
</tr>
</tbody>
</table>

Assumptions and Approach Used: For each Registrant Subsidiary, the monthly estimate for unbilled revenues is computed as net generation less the current month’s billed KWH plus the prior month’s unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used: Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the Accrued Unbilled Revenues on the balance sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required: Management considers fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used: The Registrant Subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrant Subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments are based on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. Management evaluates the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

Effect if Different Assumptions Used: There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Note 11 of the Notes to Financial Statements of Registrant Subsidiaries.
Long-Lived Assets

Nature of Estimates Required: In accordance with the requirements of SFAS 144, “Accounting for the Impairment or Disposal of Long-Lived Assets” (SFAS 144), the Registrant Subsidiaries evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, the Registrant Subsidiary records an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used: The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrant Subsidiaries estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used: In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management’s analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required: The Registrant Subsidiaries participate in AEP sponsored pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under SFAS 87, “Employers’ Accounting For Pensions”, SFAS 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions” and SFAS 158. See Note 8 of the Notes to Financial Statements of Registrant Subsidiaries for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used: The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Rate of compensation increase
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.
Effect if Different Assumptions Used: The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

<table>
<thead>
<tr>
<th>Pension Plans</th>
<th>Other Postretirement Benefits Plans</th>
</tr>
</thead>
<tbody>
<tr>
<td>+0.5%</td>
<td>-0.5%</td>
</tr>
<tr>
<td>(in millions)</td>
<td></td>
</tr>
<tr>
<td>Effect on December 31, 2008 Benefit Obligations:</td>
<td>Effect on 2008 Periodic Cost:</td>
</tr>
<tr>
<td>Discount Rate $ (182)</td>
<td>$ 198</td>
</tr>
<tr>
<td>Compensation Increase Rate 14</td>
<td>13</td>
</tr>
<tr>
<td>Cash Balance Crediting Rate 50</td>
<td>(46)</td>
</tr>
<tr>
<td>Health Care Cost Trend Rate N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Health Care Cost Trend Rate N/A</td>
<td>96</td>
</tr>
<tr>
<td>Health Care Cost Trend Rate N/A</td>
<td>(83)</td>
</tr>
<tr>
<td>N/A = Not Applicable</td>
<td></td>
</tr>
</tbody>
</table>

New Accounting Pronouncements

Adoption of New Accounting Pronouncements in 2008

The Registrant Subsidiaries partially adopted SFAS 157 in 2008 and completed the adoption of SFAS 157 effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on the Registrant Subsidiaries’ financial statements. See “SFAS 157 Fair Value Measurements” section of Note 11 for further information.

The Registrant Subsidiaries adopted SFAS 159 “The Fair Value Option for Financial Assets and Financial Liabilities” effective January 1, 2008. The statement permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. At adoption, the Registrant Subsidiaries did not elect the fair value option for any assets or liabilities.

The FASB issued SFAS 162 “The Hierarchy of Generally Accepted Accounting Principles” (SFAS 162), clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP. The Registrant Subsidiaries adopted SFAS 162 with no impact on their financial statements.

The FASB ratified EITF 06-10 “Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements” a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. The Registrant Subsidiaries adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction to beginning retained earnings. See “Pronouncements Adopted in 2008” section of Note 2.

The Registrant Subsidiaries adopted EITF 06-11 “Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards” (EITF 06-11) effective January 1, 2008. The rule addressed the recognition of income tax benefits of dividends on employee share-based compensation. The adoption of this standard had an immaterial impact on their financial statements.
The FASB issued FSP SFAS 133-1 and FIN 45-4 “Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161.” Under the SFAS 133 requirements, the seller of a credit derivative shall disclose additional information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote. Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk. The Registrant Subsidiaries adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements but increased the guarantees disclosures in Note 6.

The FASB issued FSP SFAS 140-4 and FIN 46R-8 “Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities” amending SFAS 140 “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities” and FIN 46R “Consolidation of Variable Interest Entities.” The amendments required additional disclosure regarding transfers of financial assets and variable interest entities. The Registrant Subsidiaries adopted the standards effective December 31, 2008. The adoption of these standards had no impact on the financial statements but increased the footnote disclosures for variable interest entities. See “Variable Interest Entities” section of Note 15.

FSP FIN 39-1 amends FIN 39 “Offsetting of Amounts Related to Certain Contracts” by replacing the interpretation’s definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period. This standard changed the method of netting certain balance sheet amounts. The Registrant Subsidiaries adopted FIN 39-1 effective January 1, 2008. See “Pronouncements Adopted in 2008” section of Note 2.

**New Accounting Pronouncements Adopted During the First Quarter of 2009**

The FASB issued SFAS 141R (revised “Business Combinations” 2007) improving financial reporting about business combinations and their effects. SFAS 141R can affect tax positions on previous acquisitions. The Registrant Subsidiaries do not have any such tax positions that result in adjustments. The Registrant Subsidiaries adopted SFAS 141R effective January 1, 2009. The Registrant Subsidiaries will apply it to any future business combinations.

The FASB issued SFAS 160 “Noncontrolling Interest in Consolidated Financial Statements” (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. The Registrant Subsidiaries adopted SFAS 160 retrospectively effective January 1, 2009. The adoption of this standard had an immaterial impact on the financial statements. Prior period financial statements in future filings will be comparable.

The FASB issued SFAS 161 “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard will increase disclosure requirements related to derivative instruments and hedging activities in future reports. The Registrant Subsidiaries adopted SFAS 161 effective January 1, 2009.

The FASB ratified EITF Issue No. 08-5 “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (EITF 08-5) a consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. The Registrant Subsidiaries adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as the Registrant Subsidiaries report fair value of long-term debt annually.

The FASB ratified EITF Issue No. 08-6 “Equity Method Investment Accounting Considerations” (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. The Registrant Subsidiaries prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on their financial statements.
The FASB issued FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets” amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The Registrant Subsidiaries adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

Pronouncements Effective in the Future

The FASB issued FSP SFAS 132R-1 “Employers’ Disclosures about Postretirement Benefit Plan Assets” providing additional disclosure guidance for pension and OPEB plan assets. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk. This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP’s benefit plans. The Registrant Subsidiaries will adopt the standard effective for the 2009 Annual Report.