AMERICAN ELECTRIC POWER CO INC
Form 10-Q
November 01, 2010
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2010
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
All Registrants	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark whether American Electric Power Company, Inc. has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes X No

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on the AEP corporate website, if any, every Interactive

Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes		No	

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 the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer	X	Accelerated filer	
Non-accelerated filer		Smaller reporting company	

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

Large accelerated filer		Accelerated filer	
Non-accelerated filer	X	Smaller reporting company	

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

Yes		No	X

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

	Number of shares of common stock outstanding of the registrants at October 29, 2010
American Electric Power Company, Inc.	480,276,270 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Columbus Southern Power Company	16,410,426 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
September 30, 2010

This combined Form 10-Q 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. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPEP	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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standard Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC and DCC Fuel II LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
ESP	

	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.

Term	Meaning
FTR	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.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
NOx	Nitrogen oxide.
Nonutility Money Pool	AEP’s Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.

Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.

Term	Meaning
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System’s Utility Money Pool.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- 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, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory 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 oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- 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 our dispute with Bank of America).
- 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.
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- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, 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 and demand 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, cyber security threats and other catastrophic events.
- Our ability to recover through rates any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Economic Conditions

Retail margins increased during the first nine months of 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout our service territories. In comparison to the recessionary lows of 2009, industrial sales increased 6% in the third quarter and 5% during the first nine months of 2010.

Regulatory Activity

Our significant 2010 rate proceedings include:

Kentucky – In June 2010, a settlement was approved by the KPSC to increase annual base rates by $64 million based on a 10.5% return on common equity. New rates became effective with the first billing cycle of July 2010.

Michigan – In October 2010, a settlement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity as well as the approval of certain surcharges. New rates will become effective with the first billing cycle of December 2010.

Oklahoma – In July 2010, PSO filed for an $82 million increase in annual base rates, including $30 million that is currently being recovered through a rider. The requested increase is based on an 11.5% return on common equity. Various parties' net annual rate recommendations ranged from a rate reduction of $18 million to an increase of less than $1 million. A hearing is scheduled for December 2010.

Texas – In April 2010, a settlement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on equity of 10.33%. The settlement agreement also allows SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Virginia – In July 2010, the Virginia SCC authorized an annual increase in revenues of $62 million based on a 10.53% return on equity. The order disallowed recovery of $54 million of costs related to the Mountaineer Carbon Capture and Storage Project and allowed the deferral of approximately $25 million of incremental storm expenses incurred in 2009. As a result, APCo recorded a pretax loss of $29 million in the second quarter of 2010.

West Virginia – In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million to be effective March 2011. The request is based on an 11.75% return on common equity and includes a request for recovery of and a return on the West Virginia jurisdictional share of the Mountaineer Carbon Capture and Storage Project. A decision from the WVPSC is expected in March 2011.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $132 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction and its approved air and wetlands permits. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line Certificate of Environmental Compatibility and Public Need (CECPN) appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo related to the reversal of the APSC's earlier grant of a CECPN for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant costs in Arkansas retail rates.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The Sierra Club, the Audubon Society and others filed a similar complaint in the same court. In October 2010, the motions for preliminary injunction were partially granted. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court has yet to consider the request. SWEPCo filed a notice of appeal with the Federal Court of Appeals for the Eighth Circuit and is seeking a stay of the preliminary injunction pending appeal.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Ohio Customer Choice

In our Ohio service territory, various certified retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As of September 30, 2010, approximately 2,000 Ohio retail customers have switched to alternative CRES providers while approximately 1,200 additional Ohio customers have provided notice of their intent to switch. As a result, in comparison to 2009, we lost approximately $5 million of generation related gross margin through September 30, 2010 and currently forecast incremental lost margins of approximately $10 million and $53 million for the fourth quarter of 2010 and for all of 2011, respectively. We anticipate recovery of a portion of this lost margin through off-system sales. In addition, we have created our own CRES provider to target retail customers in Ohio, both within and outside of our retail footprint.

Ohio Electric Security Plan Filings

During 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs which established rates through 2011. The order also limits annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. CSPCo and OPCo filed their 2009 significantly excessive earnings test with the PUCO. Based upon the methodology proposed by CSPCo and OPCo, neither CSPCo's nor OPCo's 2009 return on equity was significantly excessive. In October 2010, intervenors filed testimony with the PUCO recommending CSPCo return up to $156 million of its ESP revenues to customers. If the PUCO determines that CSPCo's and/or OPCo's 2009 return on equity was significantly excessive, CSPCo and/or OPCo may be required to return a portion of their ESP revenues to customers. See "Ohio Electric Security Plan Filings" section of Note 3.

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Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. The merger is also subject to regulatory approval by the FERC. CSPCo and OPCo anticipate completion of the merger during 2011. See “Proposed CSPCo and OPCo Merger” section of Note 3.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor’s warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could reduce future net income and cash flows and impact financial condition. See “Indiana Fuel Clause Filing” and “Michigan 2009 Power Supply Cost Recovery Reconciliation” sections of Note 3 and “Cook Plant Unit 1 Fire and Shutdown” section of Note 4.

Texas Restructuring Appeals

Pursuant to PUCT restructuring 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 also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT’s true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See “Texas Restructuring Appeals” section of Note 3.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, jointly constructed a CO2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO2. In APCo’s July 2009 Virginia base rate filing and APCo’s May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a pretax write-off of approximately $54 million in the second quarter of 2010. Through September 30, 2010, APCo has recorded a noncurrent regulatory asset of $59 million related to the Mountaineer Carbon Capture and Storage Project. If APCo cannot recover its remaining investments in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition. See “Mountaineer Carbon Capture and Storage Project” section of Note 3.

Capital Expenditures

In October 2010, we announced our capital expenditure budgets of $2.6 billion and $2.9 billion for 2011 and 2012, respectively.

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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 the eventual resolution will be or the timing and 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, Note 6 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to materially affect our net income.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

We are engaged in litigation about environmental issues, 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 including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. See a complete discussion of these matters in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 Annual Report.

Clean Air Act Transport Rule (Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace the Clean Air Interstate Rule (CAIR) that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO_2 and/or NO_x. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NO_x program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NO_x programs and an annual SO_2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately 1 million tons per year more SO_2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces emissions by an additional 800,000 tons per year. The SO_2 and NO_x programs rely on newly-created allowances rather than relying on the CAIR NO_x allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and the extent of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers, as these requirements could accelerate unit retirements, increase capital requirements, constrain operations, decrease reliability and unfavorably impact financial condition if the increased costs are suspended during the early development stages not recovered in rates or market prices. Comments on the proposed rule were due on October 1, 2010. Our comments pointed out the inaccuracies of some of the assumptions used by the Federal EPA, the flawed nature of its modeling analysis and unreasonable time frame for implementing the rule. We believe that the Federal EPA made erroneous assumptions about the existence and/or capabilities of current control equipment at certain of our units, used timeframes for installation of new controls that are inconsistent with our recent experience and made questionable assumptions regarding the ability to switch fuel supplies at existing units. A notice of additional information was issued and comments on that package were accepted until October 15, 2010. The proposal indicates that the requirements are expected to be finalized in June 2011 and become effective January 1, 2012.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

The Federal EPA issued the Clean Air Mercury Rule (CAMR) in 2005, setting mercury emission standards for new coal-fired power plants and requiring all states to issue new state implementation plans including mercury requirements for existing coal-fired power plants. The CAMR was vacated and remanded to the Federal EPA by the D.C. Circuit Court of Appeals in 2008. The Federal EPA issued an information collection request to owners and operators of existing power plants in 2010 to collect information to support the development of a maximum achievable control technology (MACT) standard for mercury and other hazardous air pollutant emissions under the CAA. Under the terms of a consent decree, the Federal EPA is required to issue final MACT standards for coal and oil-fired power plants by November 2011. The Federal EPA has substantial discretion in determining how to structure the MACT standards. We will urge the Federal EPA to carefully consider all of the options available so that costly and inefficient control requirements are not imposed regardless of unit size, age or other operating characteristics. However, we have approximately 5,000 MW of older coal units, including 2,000 MW of older coal-fired capacity already subject to control requirements under the NSR consent decree, for which it may be economically inefficient to install scrubbers or other environmental controls. The timing and ultimate disposition of those units will be affected by: a) the MACT standards and other environmental regulations, b) the economics of maintaining the units, c) demand for electricity, d) availability and cost of replacement power and e) regulatory decisions about cost recovery of the remaining investment in those units.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at our coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities. We estimate that the potential compliance costs associated with the proposed solid waste management alternative could be as high as a total of $3.9 billion for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs. We will seek recovery of expenditures for pollution control technologies and associated 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, these costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

While comprehensive economy-wide regulation of CO_2 emissions might be mandated through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO_2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO_2 emissions from stationary sources will be subject to regulation under the CAA beginning in

January 2011 at the earliest and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs. These rules have been challenged in the courts. The Federal EPA is reconsidering whether to include CO2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units.

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Our fossil fuel-fired generating units are very large sources of CO_2 emissions. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements.

Certain groups have filed lawsuits alleging that emissions of CO_2 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 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 4.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

For detailed information on global warming and the actions we are taking to address potential impacts, see Part I of the 2009 Form 10-K under the headings entitled "Business – General – Environmental and Other Matters – Global Warming" and "Management's Financial Discussion and Analysis of Results of Operations."

RESULTS OF OPERATIONS

SEGMENTS

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 transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing
- Wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income (Loss) Before Extraordinary Loss by segment for the three and nine months ended September 30, 2010 and 2009.

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
Utility Operations	$ 541	$ 448	$ 1,017	$ 1,121
AEP River Operations	14	10	16	22
Generation and Marketing	-	5	17	33
All Other (a)	2	(17)	(10)	(45)
Income Before Extraordinary Loss	$ 557	$ 446	$ 1,040	$ 1,131

(a) 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.
- 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 settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

Third Quarter of 2010 Compared to Third Quarter of 2009

Income Before Extraordinary Loss in 2010 increased $111 million compared to 2009 primarily due to successful rate proceedings in our various jurisdictions and favorable weather throughout our service territory.

Average basic shares outstanding increased to 480 million in 2010 from 477 million in 2009.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Income Before Extraordinary Loss in 2010 decreased $91 million compared to 2009 primarily due to $182 million of charges incurred (net of tax) related to the cost reduction initiatives partially offset by successful rate proceedings in our various jurisdictions and favorable weather conditions throughout our service territory.

Average basic shares outstanding increased to 479 million in 2010 from 452 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 480 million as of September 30, 2010.

Our results of operations are discussed below by operating segment.

UTILITY 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Revenues	$3,907	$3,389	$10,544	$9,712
Fuel and Purchased Power	1,427	1,145	3,784	3,337
Gross Margin	2,480	2,244	6,760	6,375
Depreciation and Amortization	413	412	1,205	1,173
Other Operating Expenses	1,057	988	3,411	2,975
Operating Income	1,010	844	2,144	2,227
Other Income, Net	39	42	124	97
Interest Expense	238	232	710	679
Income Tax Expense	270	206	541	524
Income Before Extraordinary Loss	$541	$448	$1,017	$1,121

Summary of KWH Energy Sales for Utility Operations
For the Three and Nine Months Ended September 30, 2010 and 2009

	Three Months Ended September 30,		Nine Months Ended September 30,	
Energy/Delivery Summary	2010	2009	2010	2009
	(in millions of KWH)			
Retail:				
Residential	17,817	15,968	48,250	44,730
Commercial	14,032	13,569	38,508	37,773
Industrial	14,460	13,642	42,503	40,563
Miscellaneous	832	798	2,328	2,291
Total Retail (a)	47,141	43,977	131,589	125,357
Wholesale	10,689	8,285	25,846	22,229
Total KWHs	57,830	52,262	157,435	147,586

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

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 Three and Nine Months Ended September 30, 2010 and 2009

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in degree days)			
Eastern Region				
Actual - Heating (a)	1	6	1,976	1,982
Normal - Heating (b)	7	7	1,918	1,969
Actual - Cooling (c)	859	509	1,294	813
Normal - Cooling (b)	691	703	984	993
Western Region				
Actual - Heating (a)	-	-	764	540
Normal - Heating (b)	1	1	596	601
Actual - Cooling (d)	1,471	1,349	2,357	2,309
Normal - Cooling (b)	1,353	1,362	2,168	2,174

(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 cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

Third Quarter of 2010 Compared to Third Quarter of 2009

Reconciliation of Third Quarter of 2009 to Third Quarter of 2010
Income from Utility Operations Before Extraordinary Loss
(in millions)

Third Quarter of 2009	$	448
Changes in Gross Margin:		
Retail Margins		246
Off-system Sales		42
Other Revenues		(52)
Total Change in Gross Margin		236
Total Expenses and Other:		
Other Operation and Maintenance		(52)
Depreciation and Amortization		(1)
Taxes Other Than Income Taxes		(17)
Interest and Investment Income		(4)
Carrying Costs Income		6
Allowance for Equity Funds Used During Construction		(6)
Interest Expense		(6)
Equity Earnings of Unconsolidated Subsidiaries		1
Total Expenses and Other		(79)
Income Tax Expense		(64)
Third Quarter of 2010	$	541

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 $246 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $31 million increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia.
    - A $22 million rate increase in Kentucky.
    - An $18 million net rate increase for SWEPCo.
    - A $16 million net rate increase for I&M.
    - A $15 million rate increase in Oklahoma.
    - A $13 million increase in the recovery of advanced metering costs in Texas.
    - A $9 million net rate increase in our other jurisdictions.
    - For the increases described above, $50 million of these rate increases relate to riders/trackers which have corresponding increases in Other Operation and Maintenance expense line

items discussed below.

- A $131 million increase in weather-related usage primarily due to a 69% increase in cooling degree days in our eastern region.
- A $19 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.

These increases were partially offset by:

- A $24 million net decrease due to a favorable fuel recovery adjustment in Ohio that was recorded in 2009.
- A $9 million decrease due to the termination of an I&M unit power agreement.

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- Margins from Off-system Sales increased $42 million primarily due to increased prices and higher physical sales volumes in our eastern region, partially offset by lower trading and marketing margins.
- Other Revenues decreased $52 million primarily due to the Cook Plant accidental outage insurance proceeds of $46 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $19 million in the third quarter of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

Total Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased $52 million primarily due to:
  - A $45 million increase in demand side management, energy efficiency, vegetation management programs and other related expenses. All of these expenses are currently recovered dollar-for-dollar in rate recovery riders/trackers in Gross Margin.
  - A $7 million increase primarily due to a net increase in employee related expenses.
- Taxes Other Than Income Taxes increased $17 million primarily due to increased revenue taxes as the result of higher than anticipated generation load and higher property taxes.
- Carrying Costs Income increased $6 million primarily due to increased environmental construction deferrals in Virginia and a higher under-recovered fuel balance for OPCo.
- Allowance for Equity Funds Used During Construction decreased $6 million primarily due to SWEPCo's completed construction of the Stall Unit in June 2010.
- Interest Expense increased $6 million primarily due to an increase in long-term debt.
- Income Tax Expense increased $64 million primarily due to an increase in pretax book income and other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Reconciliation of Nine Months Ended September 30, 2009 to Nine Months Ended September 30, 2010
Income from Utility Operations Before Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2009	$	1,121
Changes in Gross Margin:		
Retail Margins		526
Off-system Sales		43
Transmission Revenues		8
Other Revenues		(192)
Total Change in Gross Margin		385
Total Expenses and Other:		
Other Operation and Maintenance		(396)
Depreciation and Amortization		(32)
Taxes Other Than Income Taxes		(40)
Interest and Investment Income		4
Carrying Costs Income		18
Allowance for Equity Funds Used During Construction		1
Interest Expense		(31)
Equity Earnings of Unconsolidated Subsidiaries		4
Total Expenses and Other		(472)
Income Tax Expense		(17)
Nine Months Ended September 30, 2010	$	1,017

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 $526 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $106 million increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia.
    - A $38 million increase in the recovery of advanced metering costs in Texas.
    - A $34 million rate increase in Oklahoma.
    - A $31 million net increase in rates for SWEPCo.
    - A $26 million rate increase in Kentucky.
    - A $25 million rate increase in Ohio.

- A $24 million net rate increase for I&M.
- A $6 million net increase in rates in our other jurisdictions.
- For the increases described above, $115 million of these rate increases relate to riders/trackers which have corresponding increases in Other Operation and Maintenance expense line items discussed below.

- A $202 million increase in weather-related usage primarily due to a 59% increase in cooling degree days in our eastern region and a 41% increase in heating degree days in our western region.
- A $59 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Unit 1 shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.

These increases were partially offset by:

- A $27 million decrease due to the termination of an I&M unit power agreement.

- Margins from Off-system Sales increased $43 million primarily due to increased prices and higher physical sales volumes in our eastern region, partially offset by lower trading and marketing margins.

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- Transmission Revenues increased $8 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- Other Revenues decreased $192 million primarily due to the Cook Plant accidental outage insurance proceeds of $145 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $59 million in the first nine months of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above. Other Revenues also decreased due to lower gains on sales of emission allowances of $26 million, partially offset by sharing in certain fuel clauses.

Total Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased $396 million primarily due to the following:
  - A $275 million increase due to expenses related to cost reduction initiatives.
  - A $101 million increase in demand side management, energy efficiency, vegetation management programs and other related expenses. All of these expenses are currently recovered dollar-for-dollar in rate recovery riders/trackers in Gross Margin.
  - A $54 million increase due to the write-off of APCo's Virginia Share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.
  - A $33 million increase primarily due to a net increase in employee related expenses.

  These increases were partially offset by:
  - A $47 million decrease in storm related expenses primarily due to the deferral of $29 million of 2009 storm costs in Virginia as allowed by the Virginia SCC.
  - A $20 million decrease in customer assistance and other customer accounts expense.
- Depreciation and Amortization increased $32 million primarily due to new environmental control improvements placed in service at APCo, CSPCo and OPCo.
- Taxes Other Than Income Taxes increased $40 million primarily due to increased revenue taxes as the result of higher than anticipated generation load, higher property and franchise taxes and the employer portion of payroll taxes incurred related to the cost reduction initiatives.
- Carrying Costs Income increased $18 million primarily due to increased environmental construction deferrals in Virginia and a higher under-recovered fuel balance for OPCo.
- Interest Expense increased $31 million primarily due to an increase in long-term debt and a decrease in the debt component of AFUDC due to lower CWIP balances at APCo, CSPCo and OPCo.
- Income Tax Expense increased $17 million primarily due to the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits, partially offset by a decrease in pretax book income.

AEP RIVER OPERATIONS

Third Quarter of 2010 Compared to Third Quarter of 2009

Income Before Extraordinary Loss from our AEP River Operations segment increased from $10 million in 2009 to $14 million in 2010 primarily due to improved grain freight rates and increased volumes. Barge volumes increased 25% due to increased barge fleet, towboat additions and the earlier-than-normal harvest season.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Income Before Extraordinary Loss from our AEP River Operations segment decreased from $22 million in 2009 to $16 million in 2010 primarily due to expenses related to the cost reduction initiatives, increased interest expense on new equipment financing and a gain on the sale of two older towboats in 2009.

GENERATION AND MARKETING

Third Quarter of 2010 Compared to Third Quarter of 2009

Income Before Extraordinary Loss from our Generation and Marketing segment decreased from $5 million in 2009 to $0 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities and lower gross margins at the Oklaunion Plant.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Income Before Extraordinary Loss from our Generation and Marketing segment decreased from $33 million in 2009 to $17 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities partially offset by improved plant performance, hedging activities on our generation assets and increased income from our wind farm operations.

ALL OTHER

Third Quarter of 2010 Compared to Third Quarter of 2009

Income Before Extraordinary Loss from All Other increased from a loss of $17 million in 2009 to a gain of $2 million in 2010 primarily due to the recording of federal income tax adjustments.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Income Before Extraordinary Loss from All Other increased from a loss of $45 million in 2009 to a loss of $10 million in 2010 due to $16 million in pretax gains ($10 million, net of tax) on the sale of our remaining 138,000 shares of ICE in the second quarter of 2010 and the recording of federal income tax adjustments.

AEP SYSTEM INCOME TAXES

Third Quarter of 2010 Compared to Third Quarter of 2009

Income Tax Expense increased $50 million in comparison to 2009 primarily due to an increase in pretax book income and other book/tax differences which are accounted for on a flow-through basis, offset in part by federal income tax adjustments.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Income Tax Expense decreased $5 million in comparison to 2009 primarily due to a decrease in pretax book income and federal income tax adjustments, partially offset by the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

DEBT AND EQUITY CAPITALIZATION

	September 30, 2010			December 31, 2009		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$ 17,281	53.2	%	$ 17,498	56.8	%
Short-term Debt	1,466	4.5		126	0.4	
Total Debt	18,747	57.7		17,624	57.2	
Preferred Stock of Subsidiaries	60	0.2		61	0.2	
AEP Common Equity	13,656	42.1		13,140	42.6	
Total Debt and Equity Capitalization	$ 32,463	100.0	%	$ 30,825	100.0	%

Our ratio of debt-to-total capital increased from 57.2% in 2009 to 57.7% in 2010 primarily due to an increase in short-term debt of $750 million as a result of a change in an accounting standard applicable to our sale of receivables agreement and an increase of $594 million in commercial paper outstanding.

LIQUIDITY

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At September 30, 2010, we had $3.4 billion in aggregate credit facility commitments to support our operations, including our obligation to make payment of $447 million due to an unfavorable judgment issued in October 2010 related to the Bank of America litigation. See "Enron Bankruptcy" section of Note 4. Additional liquidity is available from cash from operations and a sale of receivables agreement. 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 issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At September 30, 2010, our available liquidity was approximately $3.2 billion as illustrated in the table below:

		Amount (in millions)		Maturity
Commercial Paper Backup:				
	Revolving Credit Facility	$	1,454	April 2012
	Revolving Credit Facility		1,500	June 2013
Revolving Credit Facility			478	April 2011
Total			3,432	
Cash and Cash Equivalents			1,090	
Total Liquidity Sources			4,522	
Less:	AEP Commercial Paper Outstanding		713	
	Letters of Credit Issued		602	

Net Available Liquidity	$	3,207

We have credit facilities totaling $3.4 billion, of which two $1.5 billion credit facilities support our commercial paper program. In June 2010, we terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013. These credit facilities also allow us to have letters of credit issued in an amount up to $1.35 billion. In June 2010, we also reduced the credit facility that matures in April 2011 from $627 million to $478 million. This facility can be utilized for letters of credit or draws.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2010 was $868 million. The weighted-average interest rate for our commercial paper during 2010 was 0.42%.

Securitized Accounts Receivables

In July 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

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. Debt as defined in the revolving credit agreements excludes junior subordinated debentures, securitization bonds and debt of AEP Credit. At September 30, 2010, this contractually-defined percentage was 54%. Nonperformance under these covenants could result in an event of default under these credit agreements. At September 30, 2010, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At September 30, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.46 per share in October 2010, a $0.04 increase from the prior quarter. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We have the option to defer interest payments on the AEP 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 do not believe restrictions related to our various financing arrangements, charter provisions and regulatory requirements will have any significant impact on Parent’s ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

Our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs.

CASH FLOW

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

	Nine Months Ended September 30, 2010	2009
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 490	$ 411
Net Cash Flows from Operating Activities	1,702	1,871
Net Cash Flows Used for Investing Activities	(1,575)	(2,097)
Net Cash Flows from Financing Activities	473	692
Net Increase in Cash and Cash Equivalents	600	466
Cash and Cash Equivalents at End of Period	$ 1,090	$ 877

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Nine Months Ended September 30, 2010	2009
	(in millions)	
Net Income	$ 1,040	$ 1,126
Depreciation and Amortization	1,237	1,200
Other	(575)	(455)
Net Cash Flows from Operating Activities	$ 1,702	$ 1,871

Net Cash Flows from Operating Activities were $1.7 billion in 2010 consisting primarily of Net Income of $1 billion and $1.2 billion of noncash Depreciation and Amortization. Other changes 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. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for “Transfers and Servicing” related to our sale of receivables agreement. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the American Recovery and Reinvestment Act of 2009, a change in tax accounting method and an increase in tax versus book temporary differences from operations. Due to these tax changes, Accrued Taxes, Net also increased primarily as a result of the receipt of a federal income tax refund of $419 million related to a net operating loss in 2009 that was carried back to 2007 and 2008. We also contributed $463 million to our qualified pension trust in 2010.

Net Cash Flows from Operating Activities were $1.9 billion in 2009 consisting primarily of Net Income of $1.1 billion and $1.2 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 include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity as the result of the economic slowdown and unfavorable weather conditions and an increase in under-recovered fuel primarily in Ohio and West Virginia. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a change in tax accounting method and an increase in tax versus book temporary differences from operations.

Investing Activities

	Nine Months Ended September 30, 2010	2009
	(in millions)	
Construction Expenditures	$ (1,629)	$ (2,123)
Acquisitions of Nuclear Fuel	(69)	(153)
Proceeds from Sales of Assets	160	258
Other	(37)	(79)
Net Cash Flows Used for Investing Activities	$ (1,575)	$ (2,097)

Net Cash Flows Used for Investing Activities were $1.6 billion in 2010 primarily due to Construction Expenditures for new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2010 include $139 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $2.1 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2009 include $104 million relating to the sale of a portion of Turk Plant to joint owners and $95 million for sales of transmission assets in Texas to ETT.

Financing Activities

	Nine Months Ended September 30, 2010	2009
	(in millions)	
Issuance of Common Stock, Net	$ 65	$ 1,706
Issuance/Retirement of Debt, Net	1,087	(371)
Dividends Paid on Common Stock	(602)	(564)
Other	(77)	(79)
Net Cash Flows from Financing Activities	$ 473	$ 692

Net Cash Flows from Financing Activities were $473 million in 2010. Our net debt issuances were $1.1 billion. The net issuances included issuances of $884 million of notes and $326 million of pollution control bonds, a $———594 million increase in commercial paper outstanding and retirements of $1 billion of senior unsecured notes, $148 million of securitization bonds and $222 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. We paid common stock dividends of $602 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2009 were $692 million. Issuance of Common Stock, Net of $1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $371 million. These retirements included a repayment of $2 billion outstanding under our credit facilities primarily from the proceeds of our common stock issuance and issuances of $1.6 billion of senior unsecured and debt notes and $327 million of pollution control bonds.

In October 2010, I&M retired its $150 million 6% Senior Unsecured Notes due 2032.

In November 2010, OPCo retired its $200 million 5.3% Senior Unsecured Notes due 2010.

OFF-BALANCE SHEET ARRANGEMENTS

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

	September 30, 2010	December 31, 2009
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ -	$ 631
Rockport Plant Unit 2 Future Minimum Lease Payments	1,846	1,920
Railcars Maximum Potential Loss From Lease Agreement	25	25

Effective January 1, 2010, we record the receivables and debt related to AEP Credit on our Condensed Consolidated Balance Sheet. For complete information on each of these off-balance sheet arrangements see the "Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 Annual Report.

SUMMARY OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2009 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" above.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, CSPCo, through its ownership of Conesville Coal Preparation Company (CCPC), and OPCo, through its use of the Connor Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC, CCPC and Connor Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended September 30, 2010:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	7	-	-
Number of Orders Issued under 104(b) *	-	-	-
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *	1	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-

Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ 11,472	$ -	$ -
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has two legal actions pending before the Mine Safety and Health Administration (MSHA) challenging four violations issued by MSHA following an employee fatality in March 2009.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2010

We adopted ASU 2009-16 “Transfers and Servicing” effective January 1, 2010. The adoption of this standard resulted in AEP Credit’s transfers of future receivables being accounted for as financings with the receivables and short-term debt recorded on our balance sheet.

We adopted the prospective provisions of ASU 2009-17 “Consolidations” effective January 1, 2010. We no longer consolidate DHLC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

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, financial statements, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. 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.

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 transacts in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are 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, primarily transacts in wholesale energy 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 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, coal, natural gas and emission allowances 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 Executive Vice President - Generation, 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 following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2009:

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2010
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$ 134	$ 147	$ (3)	$ 278
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(62)	(13)	5	(70)
Fair Value of New Contracts at Inception When Entered During the Period (a)	15	8	-	23
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	(1)	-	-	(1)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	(2)	(2)	-	(4)
Changes in Fair Value Due to Market Fluctuations During thePeriod (c)	11	2	-	13
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	25	-	-	25
Total MTM Risk Management Contract Net Assets at September 30, 2010	$ 120	$ 142	$ 2	264
Commodity Cash Flow Hedge Contracts				3
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(6)
Fair Value Hedge Contracts				7
Collateral Deposits				208
Total MTM Derivative Contract Net Assets at September 30, 2010				$ 476

(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. A significant portion of the total volumetric position has been economically hedged.
(b) Reflects changes in methodology in calculating the credit and discounting liability fair value adjustments.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d)

Relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody’s Investors Service, Standard & Poor’s and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of September 30, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.9%, 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 September 30, 2010, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
			(dollars in millions)		
Investment Grade	$ 801	$ 41	$ 760	2	$ 221
Split Rating	4	-	4	1	4
Noninvestment Grade	2	1	1	2	1
No External Ratings:					
Internal Investment Grade	210	-	210	2	133
Internal Noninvestment Grade	104	11	93	4	72
Total as of September 30, 2010	$ 1,121	$ 53	$ 1,068	11	$ 431
Total as of December 31, 2009	$ 846	$ 58	$ 788	12	$ 317

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Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates 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, as of September 30, 2010, 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 trading portfolio for the periods indicated:

VaR Model

Nine Months Ended September 30, 2010 (in millions)				Twelve Months Ended December 31, 2009 (in millions)			
End	High	Average	Low	End	High	Average	Low
$-	$2	$1	$-	$1	$2	$1	$-

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

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

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. As calculated on debt outstanding for both September 30, 2010 and December 31, 2009, the estimated EaR on our debt portfolio for the following twelve months was $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2010 and 2009
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2010	2009	2010	2009
REVENUES				
Utility Operations	$3,876	$3,364	$10,468	$9,666
Other Revenues	188	183	525	541
TOTAL REVENUES	4,064	3,547	10,993	10,207
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,189	931	3,098	2,624
Purchased Electricity for Resale	247	247	712	800
Other Operation	707	642	2,374	1,890
Maintenance	262	255	776	821
Depreciation and Amortization	424	421	1,237	1,200
Taxes Other Than Income Taxes	210	193	619	582
TOTAL EXPENSES	3,039	2,689	8,816	7,917
OPERATING INCOME	1,025	858	2,177	2,290
Other Income (Expense):				
Interest and Investment Income	3	5	24	5
Carrying Costs Income	18	12	51	33
Allowance for Equity Funds Used During Construction	17	23	60	59
Interest Expense	(251)	(248)	(750)	(726)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	812	650	1,562	1,661
Income Tax Expense	258	208	530	535
Equity Earnings of Unconsolidated Subsidiaries	3	4	8	5
INCOME BEFORE EXTRAORDINARY LOSS	557	446	1,040	1,131
EXTRAORDINARY LOSS, NET OF TAX	-	-	-	(5)
NET INCOME	557	446	1,040	1,126
Less: Net Income Attributable to Noncontrolling Interests	1	2	3	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	556	444	1,037	1,121
	1	1	2	2

Less: Preferred Stock Dividend Requirements of Subsidiaries				
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$555	$443	$1,035	$1,119
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	479,578,139	476,948,143	479,023,690	452,255,119
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Extraordinary Loss	$1.16	$0.93	$2.16	$2.48
Extraordinary Loss, Net of Tax	-	-	-	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.16	$0.93	$2.16	$2.47
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	479,750,447	477,111,144	479,261,415	452,495,494
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Extraordinary Loss	$1.16	$0.93	$2.16	$2.48
Extraordinary Loss, Net of Tax	-	-	-	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.16	$0.93	$2.16	$2.47
CASH DIVIDENDS PAID PER SHARE	$0.42	$0.41	$1.25	$1.23

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2010 and 2009
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	71	464	1,294				1,758
Common Stock Dividends				(559)		(5)	(564)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Purchase of JMG			55			(18)	37
Other Changes in Equity			(50)			1	(49)
SUBTOTAL – EQUITY							11,890
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $3					5		5
Securities Available for Sale, Net of Tax of $5					10		10
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $18					33		33
NET INCOME				1,121		5	1,126
TOTAL COMPREHENSIVE INCOME							1,174
TOTAL EQUITY – SEPTEMBER 30, 2009	497	$ 3,235	$ 5,826	$ 4,407	$ (404)	$ -	$ 13,064
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
Issuance of Common Stock	2	13	53				66

Common Stock Dividends				(599)		(3)	(602)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							12,606
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $1					2		2
Securities Available for Sale, Net of Tax of $5					(9)		(9)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $9					17		17
NET INCOME				1,037		3	1,040
TOTAL COMPREHENSIVE INCOME							1,050
TOTAL EQUITY – SEPTEMBER 30, 2010	500	$ 3,252	$ 5,881	$ 4,887	$ (364)	$ -	$ 13,656

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2010 and December 31, 2009
(in millions)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,090	$ 490
Other Temporary Investments	326	363
Accounts Receivable:		
Customers	585	492
Accrued Unbilled Revenues	137	503
Pledged Accounts Receivable - AEP Credit	1,029	-
Miscellaneous	108	92
Allowance for Uncollectible Accounts	(43)	(37)
Total Accounts Receivable	1,816	1,050
Fuel	811	1,075
Materials and Supplies	598	586
Risk Management Assets	279	260
Accrued Tax Benefits	165	547
Regulatory Asset for Under-Recovered Fuel Costs	95	85
Margin Deposits	86	89
Prepayments and Other Current Assets	155	211
TOTAL CURRENT ASSETS	5,421	4,756
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	24,079	23,045
Transmission	8,470	8,315
Distribution	13,940	13,549
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,867	3,744
Construction Work in Progress	2,571	3,031
Total Property, Plant and Equipment	52,927	51,684
Accumulated Depreciation and Amortization	17,929	17,340
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	34,998	34,344
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,745	4,595
Securitized Transition Assets	1,788	1,896
Spent Nuclear Fuel and Decommissioning Trusts	1,466	1,392
Goodwill	76	76
Long-term Risk Management Assets	488	343
Deferred Charges and Other Noncurrent Assets	910	946
TOTAL OTHER NONCURRENT ASSETS	9,473	9,248
TOTAL ASSETS	$ 49,892	$ 48,348

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2010 and December 31, 2009
(dollars in millions)
(Unaudited)

	2010	2009
CURRENT LIABILITIES		
Accounts Payable	$ 884	$ 1,158
Short-term Debt:		
General	716	126
Securitized Debt for Receivables - AEP Credit	750	-
Total Short-term Debt	1,466	126
Long-term Debt Due Within One Year	1,286	1,741
Risk Management Liabilities	124	120
Customer Deposits	264	256
Accrued Taxes	470	632
Accrued Interest	255	287
Regulatory Liability for Over-Recovered Fuel Costs	11	76
Liability Related to Litigation	447	-
Other Current Liabilities	941	931
TOTAL CURRENT LIABILITIES	6,148	5,327
NONCURRENT LIABILITIES		
Long-term Debt		
(September 30, 2010 amount includes $1,838 related to Transition Funding, DCC Fuel and Sabine)	15,995	15,757
Long-term Risk Management Liabilities	167	128
Deferred Income Taxes	6,928	6,420
Regulatory Liabilities and Deferred Investment Tax Credits	3,109	2,909
Asset Retirement Obligations	1,296	1,254
Employee Benefits and Pension Obligations	1,729	2,189
Deferred Credits and Other Noncurrent Liabilities	804	1,163
TOTAL NONCURRENT LIABILITIES	30,028	29,820
TOTAL LIABILITIES	36,176	35,147
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	61
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2010	2009
Shares Authorized	600,000,000	600,000,000
Shares Issued	500,319,686	498,333,265

	2010	2009
(20,278,858 shares were held in treasury at September 30, 2010 and December 31, 2009)	3,252	3,239

Paid-in Capital		5,881		5,824
Retained Earnings		4,887		4,451
Accumulated Other Comprehensive Income (Loss)		(364)		(374)
TOTAL AEP COMMON SHAREHOLDERS’ EQUITY		13,656		13,140
Noncontrolling Interests		-		-
TOTAL EQUITY		13,656		13,140
TOTAL LIABILITIES AND EQUITY	$	49,892	$	48,348
See Condensed Notes to Condensed Consolidated Financial Statements.				

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2010 and 2009
(in millions)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$1,040	$1,126
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,237	1,200
Deferred Income Taxes	404	662
Extraordinary Loss, Net of Tax	-	5
Carrying Costs Income	(51)	(33)
Allowance for Equity Funds Used During Construction	(60)	(59)
Mark-to-Market of Risk Management Contracts	(108)	(99)
Amortization of Nuclear Fuel	113	41
Property Taxes	157	144
Fuel Over/Under-Recovery, Net	(233)	(377)
Pension Contributions to Qualified Plan Trust	(463)	-
Change in Other Noncurrent Assets	(50)	13
Change in Other Noncurrent Liabilities	183	164
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(766)	68
Fuel, Materials and Supplies	240	(394)
Margin Deposits	3	(15)
Accounts Payable	(163)	(29)
Customer Deposits	8	11
Accrued Taxes, Net	223	(165)
Accrued Interest	(32)	(38)
Other Current Assets	35	(71)
Other Current Liabilities	(15)	(283)
Net Cash Flows from Operating Activities	1,702	1,871
INVESTING ACTIVITIES		
Construction Expenditures	(1,629)	(2,123)
Change in Other Temporary Investments, Net	63	72
Purchases of Investment Securities	(1,542)	(573)
Sales of Investment Securities	1,477	524
Acquisitions of Nuclear Fuel	(69)	(153)
Acquisitions of Assets	(16)	(70)
Proceeds from Sales of Assets	160	258
Other Investing Activities	(19)	(32)
Net Cash Flows Used for Investing Activities	(1,575)	(2,097)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	65	1,706
Issuance of Long-term Debt	1,201	1,912
Borrowings from Revolving Credit Facilities	195	90

Change in Short-term Debt, Net	1,223	347
Retirement of Long-term Debt	(1,454)	(659)
Repayments to Revolving Credit Facilities	(78)	(2,061)
Principal Payments for Capital Lease Obligations	(74)	(62)
Dividends Paid on Common Stock	(602)	(564)
Dividends Paid on Cumulative Preferred Stock	(2)	(2)
Other Financing Activities	(1)	(15)
Net Cash Flows from Financing Activities	473	692
Net Increase in Cash and Cash Equivalents	600	466
Cash and Cash Equivalents at Beginning of Period	490	411
Cash and Cash Equivalents at End of Period	$1,090	$877
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$755	$744
Net Cash Paid (Received) for Income Taxes	(243)	(74)
Noncash Acquisitions Under Capital Leases	190	53
Construction Expenditures Included in Accounts Payable at September 30,	229	229

See Condensed Notes to Condensed Consolidated Financial Statements.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed consolidated financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2010 is not necessarily indicative of results that may be expected for the year ending December 31, 2010. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2009 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 26, 2010.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability 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 were applied consistently. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are the primary beneficiary of Sabine, DCC Fuel LLC, DCC Fuel II LLC, AEP Credit, Transition Funding and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLC as defined by the new accounting guidance for "Variable Interest Entities." In addition, we have not provided material financial or other support to Sabine, DCC Fuel LLC, DCC Fuel II LLC, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series) and DHLC.

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. In addition, SWEPCo determines how much coal will be mined for each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended September 30, 2010 and 2009 were $30 million and $34 million, respectively, and for the nine months ended September 30, 2010 and 2009 were $103 million and $95 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Condensed Consolidated Balance Sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows 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 our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the three months ended September 30, 2010 and 2009 were $15 million and $13 million, respectively, and for the nine months ended September 30, 2010 and 2009 were $33 million and $30 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Condensed Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. DCC Fuel LLC and DCC Fuel II LLC (collectively DCC Fuel) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the leases are made semi-annually and began in April 2010. Payments on the leases for the nine months ended September 30, 2010 were $22 million. No payments were made to DCC Fuel during the third quarter of 2010 and during the year 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 and 54 month lease term, respectively. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Condensed Consolidated Balance Sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables sold for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our Condensed Consolidated Balance Sheets. See the "ASU 2009-17 'Consolidation' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010. Also, see "Sale of Receivables – AEP Credit" section of Note 14 in the 2009 Annual Report for further information.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. Based on the shared control of DHLC's operations, management concluded as of January 1, 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC. SWEPCo's total billings from DHLC for the three months ended September 30, 2010 and 2009 were $14 million and $12 million, respectively, and for the nine months ended September 30, 2010 and 2009 were $40 million and $31 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on our Condensed Consolidated Balance Sheet at December 31, 2009 as well as our investment and maximum exposure as of September 30, 2010. As of January 1, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.8 billion at September 30, 2010 and are included in current and long-term debt on the Condensed Consolidated Balance Sheets. Transition Funding has securitized transition assets of $1.8 billion at September 30, 2010, which are presented separately on the face of the Condensed Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition asset and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
September 30, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	Transition Funding
ASSETS					
Current Assets	$ 42	$ 92	$ 143	$ 1,004	$ 160
Net Property, Plant and Equipment	142	118	-	-	-
Other Noncurrent Assets	35	80	1	10	1,791
Total Assets	$ 219	$ 290	$ 144	$ 1,014	$ 1,951
LIABILITIES AND EQUITY					
Current Liabilities	$ 26	$ 65	$ 40	$ 961	$ 196
Noncurrent Liabilities	193	225	90	1	1,741
Equity	-	-	14	52	14
Total Liabilities and Equity	$ 219	$ 290	$ 144	$ 1,014	$ 1,951

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	I&M DCC Fuel	Protected Cell of EIS
ASSETS				
Current Assets	$ 51	$ 8	$ 47	$ 130
Net Property, Plant and Equipment	149	44	89	-
Other Noncurrent Assets	35	11	57	2
Total Assets	$ 235	$ 63	$ 193	$ 132
LIABILITIES AND EQUITY				
Current Liabilities	$ 36	$ 17	$ 39	$ 36
Noncurrent Liabilities	199	38	154	74
Equity	-	8	-	22
Total Liabilities and Equity	$ 235	$ 63	$ 193	$ 132

Our investment in DHLC was:

September 30, 2010
As Reported on

	the Consolidated Balance Sheet		Maximum Exposure
		(in millions)	
Capital Contribution from SWEPCo	$ 7		$ 7
Retained Earnings	2		2
SWEPCo's Guarantee of Debt	-		42
Total Investment in DHLC	$ 9		$ 51

In September 2007, we and Allegheny Energy Inc. (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 AEP, 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 provisions that make PATH-WV a VIE. Neither the "Ohio Series" nor "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Condensed 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 should be consistent with other regulated utilities. 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. 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 was:

	September 30, 2010		December 31, 2009	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 16	$ 16	$ 13	$ 13
Retained Earnings	6	6	3	3
Total Investment in PATH-WV	$ 22	$ 22	$ 16	$ 16

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts Attributable to AEP Common Shareholders	2010	2009	2010	2009
	(in millions)			
Income Before Extraordinary Loss	$ 555	$ 443	$ 1,035	$ 1,124
Extraordinary Loss, Net of Tax	-	-	-	(5)
Net Income	$ 555	$ 443	$ 1,035	$ 1,119

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 Condensed Consolidated Statements of Income:

	Three Months Ended September 30,			
	2010		2009	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 555		$ 443	
Weighted Average Number of Basic Shares Outstanding	479.6	$ 1.16	476.9	$ 0.93
Weighted Average Dilutive Effect of:				
Performance Share Units	-	-	0.1	-
Stock Options	0.1	-	-	-
Restricted Stock Units	0.1	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	479.8	$ 1.16	477.1	$ 0.93

	Nine Months Ended September 30,			
	2010		2009	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 1,035		$ 1,119	
Weighted Average Number of Basic Shares Outstanding	479.0	$ 2.16	452.3	$ 2.47
Weighted Average Dilutive Effect of:				
Performance Share Units	0.1	-	0.2	-
Stock Options	0.1	-	-	-
Restricted Stock Units	0.1	-	-	-
Weighted Average Number of Diluted Shares Outstanding	479.3	$ 2.16	452.5	$ 2.47

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

Options to purchase 136,250 and 612,916 shares of common stock were outstanding at September 30, 2010 and 2009, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive.

Supplementary Information

Related Party Transactions	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
AEP Consolidated Revenues – Utility Operations:				
Ohio Valley Electric Corporation (43.47% owned)	$ -	$ -	$ (20)(a)	$ -
AEP Consolidated Revenues – Other Revenues:				
Ohio Valley Electric Corporation – Barging and Other	6	7	22	22

Transportation Services (43.47% Owned)				
AEP Consolidated Expenses – Purchased Energy for Resale:				
Ohio Valley Electric Corporation (43.47% Owned)	66	71	223 (b)	213

(a) In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales through June 2010.

(b) In January 2010, the AEP Power Pool began purchasing power from OVEC to serve retail sales through June 2010. The total amount reported includes $10 million related to this agreement.

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Adjustments to Reported Cash Flows

In the Financing Activities section of our Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2009, we corrected the presentation of borrowings on our lines of credit of $90 million from Change in Short-term Debt, Net to Borrowings from Revolving Credit Facilities. We also corrected the presentation of repayments on our lines of credit of $2.1 billion for the nine months ended September 30, 2009 to Repayments to Revolving Credit Facilities from Change in Short-term Debt, Net. The correction to present borrowings and repayments on our lines of credit on a gross basis was not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or net cash flows from financing activities.

Adjustments to Securitized Accounts Receivable Disclosure

In the "Securitized Accounts Receivable – AEP Credit" section of Note 11, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or cash flows.

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 impact our financial statements.

Pronouncements Adopted During 2010

The following standards were effective during the first nine months of 2010. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2009-16 "Transfers and Servicing" (ASU 2009-16)

In 2009, the FASB issued ASU 2009-16 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

We adopted ASU 2009-16 effective January 1, 2010. AEP Credit transfers an interest in receivables it acquires from certain of its affiliates to bank conduits and receives cash. As of December 31, 2009, AEP Credit owed $656 million to bank conduits related to receivable sales outstanding. Upon adoption of ASU 2009-16, future transactions do not constitute a sale of receivables and are accounted for as financings. Effective January 2010, we record the receivables and related debt on our Condensed Consolidated Balance Sheet.

ASU 2009-17 "Consolidations" (ASU 2009-17)

In 2009, the FASB issued ASU 2009-17 amending the analysis an entity must perform to determine if it has a controlling financial interest in a VIE. In addition to presentation and disclosure guidance, ASU 2009-17 provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
-

The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

We adopted the prospective provisions of ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, we report DHLC using the equity method of accounting.

This standard increased our disclosure requirements for AEP Credit and Transition Funding, wholly-owned consolidated subsidiaries. See “Variable Interest Entities” section of Note 1 for further discussion.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo’s SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo’s SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied “Regulated Operations” accounting guidance for the generation portion of SWEPCo’s Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of “Regulated Operations” accounting guidance resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. RATE MATTERS

As discussed in the 2009 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2009 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2010 and updates the 2009 Annual Report.

Regulatory Assets Not Yet Being Recovered

	September 30, 2010	December 31, 2009
	(in millions)	
Noncurrent Regulatory Assets (excluding fuel)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Earning a Return		
Customer Choice Deferrals - CSPCo, OPCo	$ 58	$ 57
Storm Related Costs - CSPCo, OPCo, TCC	52	49
Line Extension Carrying Costs - CSPCo, OPCo	52	43
Acquisition of Monongahela Power - CSPCo	7	10
Regulatory Assets Currently Not Earning a Return		
Mountaineer Carbon Capture and Storage Project - APCo	59	111
Environmental Rate Adjustment Clause - APCo	48	25
Storm Related Costs - APCo, PSO, KGPCo	44	-
Deferred Wind Power Costs - APCo	24	5
Transmission Rate Adjustment Clause - APCo	21	26
Special Rate Mechanism for Century Aluminum - APCo	13	12
Acquisition of Monongahela Power - CSPCo	4	-

Storm Related Costs - KPCo		-	(a)		24
Peak Demand Reduction/Energy Efficiency - CSPCo, OPCo		-	(a)		8
Total Regulatory Assets Not Yet Being Recovered	$	382		$	370

(a) Recovery of regulatory asset was granted during 2010.

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CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved CSPCo's and OPCo's ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limits annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC increase is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the "2009 Fuel Adjustment Clause Audit" section below. The order allows CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at CSPCo's and OPCo's weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the "Ormet Interim Arrangement" section below. The FAC deferrals as of September 30, 2010 were $15 million and $433 million for CSPCo and OPCo, respectively, excluding $2 million and $24 million, respectively, of unrecognized equity carrying costs.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMARTSM and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In April 2010, the Industrial Energy Users-Ohio filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In 2009, the PUCO convened a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET). Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. The PUCO heard arguments related to various SEET issues including the treatment of the FAC deferrals. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets until they are collected, even assuming there are significantly excessive earnings in that year. In June 2010, the PUCO issued an order resolving some of the SEET issues. The PUCO determined that the earnings of CSPCo and OPCo shall be calculated on an individual company basis and not on a combined CSPCo/OPCo basis. The PUCO ruled that many issues, including the treatment of deferrals and off-system sales, should be determined on a case-by-case basis. The PUCO's decision on the SEET methodology is not expected to be finalized until after the PUCO issues an order on the SEET filings. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo's and OPCo's returns on common equity were 20.84% and 10.81%, respectively, including off-system sales margins and 18.31% and 9.42%, respectively, excluding off-system sales margins. Included in the filings was CSPCo's and OPCo's determination that the level at which their earned return on common equity may become significantly in excess of the average earned return on common equity of the comparable risk group of publicly traded firms was 22.51%. Based upon the methodology proposed by CSPCo and OPCo in the SEET filings, neither CSPCo’s nor OPCo’s 2009 return on common equity was significantly excessive. In October 2010, the PUCO staff filed testimony that recommended a return on common equity over 16.05% as significantly excessive but did not address whether adjustments for off-system sales (OSS) and deferrals should be made to reduce the return. Also, in October 2010, intervenors, including the Ohio Consumers’ Counsel, filed testimony with the PUCO recommending an acceptable return on common equity in the range of 11.58% to 13.58%. As a result, the intervenors recommended CSPCo refund up to $156 million of its 2009 earnings. If the PUCO determines that CSPCo’s and/or OPCo’s 2009 return on common equity was significantly excessive, CSPCo and/or OPCo may be required to return a portion of their ESP revenues to customers.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. The merger is also subject to regulatory approval by the FERC. CSPCo and OPCo anticipate completion of the merger during 2011.

Requested Sporn Unit 5 Shutdown and Proposed Distribution Rider

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider, outside the rate caps established in the ESP proceeding. The proposed rider would recover the net book value of the unit as well as related materials and supplies as of December 2010, which is estimated to be $59 million, as well as future closure costs incurred after December 2010. OPCo also requested the PUCO to grant accounting authority to record the future closure costs as a regulatory asset or regulatory liability with a weighted average cost of capital carrying charge to be included in the proposed non-bypassable distribution rider after they are incurred. Also in October 2010, OPCo filed a retirement notification with PJM pending PUCO approval of OPCo’s application to close Sporn Unit 5. Absent PUCO approval, management intends to operate Sporn Unit 5 through 2013. Management is unable to predict the outcome of this proceeding.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report of the FAC audit to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo’s FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million will reduce fuel expense in 2009 and 2010. If the PUCO orders any portion of the $58 million previously recognized or potential other future adjustments be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had $30 million and $34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges but excluding $1 million and $1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP orders.

As of September 30, 2010, CSPCo and OPCo have incurred $39 million and $30 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $27 million and $20 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $12 million and $10 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. The carrying costs include both a return of and on the environmental investments as well as related administrative and general expenses and taxes. In August 2010, the PUCO issued an order approving a rider of approximately $26 million and $34 million for CSPCo and OPCo, respectively, effective September 2010. The implementation of the rider will likely not impact cash flows, but will increase the ESP phase-in plan deferrals associated with the FAC since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through September 30, 2010, CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each 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 before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $132 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $132 million for transmission, excluding AFUDC. As of September 30, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $957 million of expenditures (including AFUDC and capitalized interest of $121 million and related transmission costs of $58 million). As of September 30, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $339 million (including related transmission costs of $5 million). SWEPCo's share of the contractual construction commitments is $249 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of September 30, 2010, of approximately $121 million (including related transmission cancellation fees of $1 million). SWEPCo's share of the contractual construction cancellation fees would be approximately $89 million.

Discussed below are the significant outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo. Therefore, SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal

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contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club petitioned the LPSC to begin an investigation into the construction of the Turk Plant which was rejected by the LPSC. The Sierra Club later refiled its petition as a stand alone complaint proceeding. SWEPCo filed a motion to dismiss and denied the allegations in the complaint. In October 2010, an Administrative Law Judge recommended the LPSC dismiss the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas.

The wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In February 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. In May 2010, plaintiffs filed with the Federal District Court for the Western District of Arkansas seeking a preliminary injunction to halt construction and for a temporary restraining order.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of the Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The plaintiffs' federal law claims challenge the process used and terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. The plaintiffs' state law claims challenge SWEPCo's ability to construct the Turk Plant without obtaining a certificate from the APSC. This motion for preliminary injunction was heard simultaneously with the motion filed by the Sierra Club. In October 2010, the motions for preliminary injunction were partially granted. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court has yet to consider the request. SWEPCo filed a notice of appeal with the Federal Court of Appeals for the Eighth Circuit and is seeking a stay of the preliminary injunction pending appeal.

In January 2009, SWEPCo was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenors appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines. A hearing is scheduled for January 2011.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction, including the related transmission facilities, and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of September 30, 2010, the Stall Unit cost $423 million, including $49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap. In July 2010, the Stall Unit was placed into Arkansas rates. SWEPCo received CWIP treatment for a portion of the Stall Unit in the 2009 Texas Base Rate Filing. See "2009 Texas Base Rate Filing" section below. The Stall Unit will be phased into Louisiana rate base between October 2010 and October 2011.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on common equity of 11.5%. The filing included requests for financing cost riders of $32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $27 million. In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on common equity of 10.33%, which consists of $5 million related to construction of the Stall Unit and $10 million in other increases. In addition, the settlement agreement will decrease annual depreciation expense by $17 million and allows SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from $3 million to $30 million in SWEPCo's $755 million fuel and purchase power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions.

In September 2010, the Administrative Law Judges issued a Proposal for Decision (PFD) that recommended a disallowance of a significant portion of the charges to a ten-year gas transportation agreement that began in 2009 for the Mattison Plant located in Northwest Arkansas. The PFD stated that SWEPCo should have pursued other transportation options or sought the supplier's recourse rate from the FERC. The estimated recommended disallowance over the ten-year period through December 2018 is $107 million for which the estimated Texas jurisdictional portion is $37 million. In addition, the PFD also contained recommendations to disallow risk premiums related to the ERCOT trading contracts transferred to AEPEP which are estimated to be $1.5 million on a Texas retail jurisdictional basis. Through September 30, 2010, SWEPCo's management estimated the impact of this PFD, if adopted by the PUCT, to be $7 million. In October 2010, SWEPCo filed exceptions on these issues with the PUCT. An order may be issued in the fourth quarter of 2010. Management is unable to predict the outcome of this reconciliation. If the PUCT disallows any portion of SWEPCo's fuel and purchase power costs, it could reduce future net income and cash flows and possibly impact financial condition.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring 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 also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision. An October 2010 decision of the Texas Supreme Court addressing the same issue for another utility upholds the Court of Appeals determination.

- The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.

- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated Retail Electric Providers (REPs). This decision could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income and cash flows and possibly impact financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of $103 million plus interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS' private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. TCC is not accruing interest on the $103 million because it is not probable that the PUCT will order TCC to violate the normalization provision of the Internal Revenue Code. If interest were accrued, management estimates interest expense would have been approximately $20 million higher for the period July 2008 through September 2010.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the resulting normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates $101 million as of September 30, 2010. 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 its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows and impact 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 Retail Electric Providers (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 costs in the true-up proceeding.

Certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows and impact financial condition. Management cannot predict the outcome of the excess earnings remand.

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

TCC filed a base rate case in 2006 seeking to increase base rates. The PUCT issued an order in 2007 which increased TCC's base rates by $20 million, eliminated a merger credit rider of $20 million and reduced depreciation rates by $7 million. The PUCT decision was appealed by TCC and various intervenors. On appeal, the Texas District Court affirmed the PUCT in most respects. Various intervenors appealed that decision. In June 2010, the Texas Court of Appeals affirmed the Texas District Court's decision. The order became final with an August 2010 Texas Court of Appeals mandate.

ETT 2007 Formation Appeal

ETT is a joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC. TCC and TNC have sold transmission assets both in service and under construction to ETT. The PUCT approved ETT's initial rates, a request for a transfer of in-service assets and CWIP and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in ERCOT. ETT was allowed a 9.96% return on common equity. Intervenors appealed the PUCT's decision. In March 2010, the Texas Court of Appeals affirmed the PUCT's decision in all material respects. Intervenors filed for rehearing at the Texas Court of Appeals which was denied in May 2010. The deadline to appeal this decision to the Texas Supreme Court has expired.

In a separate development, the Texas governor signed a new law that clarifies the PUCT's authority to grant CCNs to transmission only utilities such as ETT. ETT filed an application with the PUCT for a CCN under the new law. In March 2010, the PUCT approved the application for a CCN under the new law.

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a $62 million increase based on a 10.53% return on common equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project, which resulted in a pretax write-off of $54 million in the second quarter of 2010. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral of approximately $25 million of incremental storm expense incurred in 2009. In July 2010, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project which was denied in August 2010. Approximately $3 million, including interest, was refunded to customers in September 2010 related to the collection of interim rates.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. Hearings are scheduled for December 2010. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO2. In October 2009, APCo started injecting CO2 into the underground storage facilities. The injection of CO2 required the recording of an asset retirement obligation and an offsetting regulatory asset. Through September 30, 2010, APCo has recorded a noncurrent regulatory asset of $59 million related to the Mountaineer Carbon Capture and Storage Project.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs. See "2009 Virginia Base Rate Case" section above.

In APCo's May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. If APCo cannot recover its remaining investment in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition.

APCo's Filings for an IGCC Plant

APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC power plant in Mason County, West Virginia. APCo also requested the Virginia SCC and the WVPSC to approve a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on common equity once the facility is placed into commercial operation. The WVPSC granted APCo the CPCN and approved the requested cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order.

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism based upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on an unfavorable order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

Through September 30, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and in West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

APCo’s and WPCo’s 2009 Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo’s and WPCo’s March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $355 million and a first-year increase of $124 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan and lowered annual coal cost projections by $27 million. As of September 30, 2010, APCo’s ENEC under-recovery balance was $365 million, excluding $1 million of unrecognized equity carrying costs, which is included in noncurrent regulatory assets.

In June 2010, a settlement agreement for $96 million, including $10 million of construction surcharges, was filed with the WVPSC related to APCo’s and WPCo’s second year ENEC increase. The settlement agreement provided for recovery of the amounts related to the renegotiated coal contracts and allows APCo to accrue weighted average cost of capital carrying costs on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. In June 2010, the WVPSC approved the settlement agreement which made rates effective in July 2010.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of $42 million of PSO fuel costs. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) has contended that PSO should not have collected the $42 million without specific OCC approval. As such, the OIEC contends that the OCC should require PSO to refund the $42 million it collected through its fuel clause. The OCC has heard the OIEC appeal and a decision is pending. In March 2010, PSO filed motions to advance this proceeding since the FERC has ruled on the allocation of off-system sales margins and PSO has refunded the additional margins to its retail customers. If the OCC were to order PSO to refund all or a part of the $42 million, it would reduce future net income and cash flows and impact financial condition.

2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. A hearing is scheduled for January 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an $81 million increase in PSO’s non-fuel base revenues based on a 10.5% return on common equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. In June 2010, the Court of Civil Appeals affirmed the OCC's decision. No parties sought rehearing or appeal and, as a result, this case has concluded.

2010 Oklahoma Base Rate Case

In July 2010, PSO filed a request with the OCC to increase annual base rates by $82 million, including $30 million that is currently being recovered through a rider. The requested net annual increase to ratepayers would be $52 million. The requested increase includes a $24 million increase in depreciation and an 11.5% return on common equity. In October 2010, various parties, including the OCC staff, filed testimony regarding PSO’s requested base rate increase. These parties proposed that PSO's request to increase depreciation rates be denied and that existing depreciation rates continue. PSO’s request to move the $30 million currently recovered through a rider to base rates was not opposed. The parties’ net annual rate recommendations ranged from a rate reduction of $18 million to an increase of less than $1 million based on a recommended return on common equity range from 9.5% to 10%. A hearing is scheduled for December 2010.

I&M Rate Matters

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately $53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the “Cook Plant Unit 1 Fire and Shutdown” section of Note 4, Cook Unit 1 (Unit 1) was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduced power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the remaining costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. I&M maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers’ bills by $78 million. In October 2010, the Indiana/Michigan Industrial Group and the Indiana Office of Utility Consumer Counselor filed testimony which recommended I&M pay to customers a portion of the accidental outage insurance proceeds up to the extent not previously paid to customers through the fuel adjustment clause or needed to cover costs not covered by I&M’s property damage insurance policy. Hearings are scheduled to be held in January 2011.

Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be paid to customers, it would reduce future net income and cash flows and impact financial condition.

Michigan 2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be paid to customers, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

Michigan Base Rate Filing

In January 2010, I&M filed with the MPSC a request for a $63 million increase in annual base rates based on an 11.75% return on common equity. Starting with the August 2010 billing cycle, I&M, with the MPSC authorization, implemented a $44 million interim rate increase. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In October 2010, a settlement agreement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity, effective December 2010, plus separate recovery of approximately $7 million of customer choice implementation costs over a two year period beginning April 2011. In addition, the approved revenue requirement includes the amortization of $6 million in previously expensed restructuring costs over five years, which I&M will defer and begin amortizing in the fourth quarter of 2010. Also, the approved settlement agreement provided for sharing of off-system sales margins between customers (75%) and I&M (25%) with customers receiving a credit in future Power Supply Cost Recovery proceedings for their jurisdictional share of any off-system sales margins. In September 2010, I&M recorded a provision for refund of $2 million, including interest, related to the implementation of interim rates.

Kentucky Rate Matters

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. The base rate case also requested recovery of deferred storm restoration expenses over a three-year period.

A settlement agreement was filed with the KPSC to increase base revenue by $64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of $23 million of deferred storm restoration expenses over five years. In June 2010, the KPSC approved the settlement agreement as filed. New rates became effective the first billing cycle of July 2010.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the 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 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues.

In 2006, a FERC Administrative Law Judge (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 any unpaid SECA rates must be paid in the recommended reduced amount.

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 May 2010, the FERC issued an order that generally supports AEP’s position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC regarding certain matters including a request to clarify the method for determining the amount of such revenues. The request also asked the FERC to clarify that interest may be added to SECA charges originally billed to but never paid by Green Mountain Energy (reassigned to British Petroleum Energy). Eight other groups also filed requests for rehearing with the FERC.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $12 million including estimated interest of $3 million. A decision is pending from the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the AEP East companies’ analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties’ 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. In August 2010, a settlement agreement was filed with the FERC. In October 2010, the FERC approved the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years. However, management is unable to predict whether the parties to the TA will experience regulatory lag and its effect on future net income and cash flows.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO disputes PJM’s methodology.

Settlement discussions between MISO and PJM have been unsuccessful, and as a result, in March 2010, MISO filed two related complaints against PJM at the FERC related to the above claim. MISO seeks to recover a total of approximately $145 million from PJM. If PJM is held liable for these damages, PJM members, including the AEP East companies, may be billed for a share of the refunds or payments PJM is directed to make to MISO. AEP has intervened and filed a protest to one complaint. Management believes that MISO's claims are without merit and that PJM's right to recover any MISO damages from AEP and other members is limited. If the FERC orders a settlement above the AEP East companies’ reserve related to their estimated portion of PJM additional costs, it could reduce future net income and cash flows and impact financial condition.

4. 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. The Commitments, Guarantees and Contingencies note within our 2009 Annual Report should be read in conjunction with this report.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." 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 with third parties. 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. We have two $1.5 billion credit facilities, of which $750 million may be issued under one credit facility as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013 and allows for the issuance of up to $600 million as letters of credit. As of September 30, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $125 million with maturities ranging from November 2010 to November 2011.

In June 2010, we reduced the $627 million credit agreement to $478 million. As of September 30, 2010, $477 million of letters of credit with maturities ranging from November 2010 to April 2011 were issued by subsidiaries under this 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 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), a consolidated variable interest entity. 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 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of September 30, 2010, SWEPCo has collected approximately $47 million through a rider for final mine closure and reclamation costs, of which $1 million is recorded in Other Current Liabilities, $23 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $23 million is recorded in Asset Retirement Obligations on our Condensed 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

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 sale agreements is discussed in the 2009 Annual Report "Dispositions" section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price. This maximum exposure of approximately $1 billion relates to the Bank of America (BOA) litigation (see "Enron Bankruptcy" section of this note), of which the probable payment/performance risk is $447 million and is recorded in Current Liabilities - Liability Related to Litigation on our Condensed Consolidated Balance Sheet as of September 30, 2010. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, we 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. We are currently in negotiations to replace this agreement. In December 2008 and 2009, we signed new master lease agreements that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 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 value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair 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 a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At September 30, 2010, the maximum potential loss for these lease agreements was approximately $3 million assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

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 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 $18 million for I&M and $20 million for SWEPCo for the remaining railcars as of September 30, 2010.

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 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 value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair 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.

ENVIRONMENTAL 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 and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. Following a second liability trial in 2009, the jury again found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. In October 2010, the Seventh Circuit dismissed all of the remaining claims in these cases. Beckjord is operated by Duke Energy Ohio, Inc.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in the pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects and pay a portion of plaintiffs' attorneys' fees and costs.

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 a previous state permit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. 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. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 (TVA). 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 trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. The defendants' petition for rehearing was denied. We believe the actions are without merit and intend to continue to defend against the claims. The defendants, excluding TVA, filed a petition for review with the U.S. Supreme Court in August 2010. The Solicitor General filed a brief in support of the petition on behalf of TVA. Responses to the petition are due in November 2010.

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In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. We were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. Responses to the petition are due in November 2010.

We are unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 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 and 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. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

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. In May 2008, I&M started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $11 million of expense prior to January 1, 2010, $3 million of which I&M recorded in March 2009. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

Amos Plant – State and Federal Enforcement Proceedings

In March 2010, we received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with particulate matter emission limits) that lasted for more than thirty consecutive minutes in a 24-hour period and that certain required notifications were not made. We met with representatives of DAQ to discuss these occurrences and the steps we have taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. We have denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. We continue to discuss the resolution of these issues with DAQ, but cannot predict the outcome of these discussions or the amount of any penalty that may be assessed.

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. We indicated our willingness to engage in good faith negotiations and provided additional information to representatives of the Federal EPA. We have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable.

We are unable to determine a range of potential losses that are reasonably possible of occurring for either of these pending issues.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several units utilizing the jet bubbling reactor (JBR) technology. The retrofits on two Cardinal Plant units and a Conesville Plant unit are operational. Contracts for other projects were suspended during their early development stages. Due to unexpected operating results, we completed an extensive review in 2009 of the design and manufacture of the JBR internal components. Our review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. In August 2010, we signed a settlement agreement with Black & Veatch that resolved the issues involving the internal components. We also reached an agreement in principle regarding JBR vessel corrosion issues. These settlements result in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. 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. 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. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small 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. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 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. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of September 30, 2010, we recorded $53 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. Through September 30, 2010, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. Intervenors in the Indiana fuel clause proceeding recommend the remaining accidental outage policy revenues should be given to customers through the fuel clause. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease, but no agreement was reached prior to the end of the lease. Fort Wayne issued a technical notice of default under the lease to I&M in August 2009. I&M responded to Fort Wayne in October 2009 that it did not agree there was a default under the lease. In October 2009, I&M filed for declaratory and injunctive relief in Indiana state court. The parties agreed to submit this matter to mediation. In February 2010, the court issued a stay to continue mediation. I&M is expensing monthly payments made into an escrow account in lieu of rent.

I&M and Fort Wayne reached a tentative agreement as a result of the mediation process. The agreement was signed on October 28, 2010 and is subject to approval by the Fort Wayne Common Council and the IURC. I&M and Fort Wayne have agreed to cooperate in promptly seeking the requisite approvals. If the agreement is approved, I&M will purchase the remaining leased property and settle claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, inclusive of interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. I&M will seek recovery in rates of the payments made to Fort Wayne. If the agreement is not approved by the Fort Wayne Common Council and the IURC, the parties have the right to terminate the agreement and pursue other relief.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (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, which 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 contesting Enron's right to reject these agreements.

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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 misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the 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 2005, the Judge 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. Trial in federal court in Texas was continued pending a decision in the New York case.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the New York court entered a final judgment of $346 million. We appealed and posted a bond covering the amount of the judgment entered against us. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed this award and posted bond covering that amount. In October 2010, the Court of Appeals affirmed the New York district court's decision as to the final judgment of $346 million and reversed the New York district court as to the judgment dismissing our claims against BOA in the Southern District of Texas. We intend to pursue these claims in Texas.

The liability for the BOA litigation, including interest, was $447 million at September 30, 2010 and is included in Current Liabilities - Liability Related to Litigation on the Condensed Consolidated Balance Sheet. $441 million related to this matter was included in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheet at December 31, 2009. This decision will have no impact on consolidated net income for 2010.

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 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. We are unable to determine a range of potential losses that are reasonably possible of occurring.

5. ACQUISITION AND DISPOSITIONS

ACQUISITION

2010

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). In October 2010, SWEPCo finalized the purchase for approximately $102 million, subject to working capital and other adjustments, and began serving VEMCO's 30,000 customers in Louisiana.

2009

None

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DISPOSITIONS

2010

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold $66 million and $73 million, respectively, of transmission facilities to ETT for the nine months ended September 30, 2010. There were no gains or losses recorded on these transactions.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain ($10 million, net of tax). We recorded the gain in Interest and Investment Income on our Condensed Consolidated Statements of Income for the nine months ended September 30, 2010.

2009

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold $93 million and $1 million, respectively, of transmission facilities to ETT for the nine months ended September 30, 2009. There were no gains or losses recorded on these transactions.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost for the plans for the three and nine months ended September 30, 2010 and 2009:

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Service Cost	$ 28	$ 26	$ 12	$ 11
Interest Cost	63	64	29	27
Expected Return on Plan Assets	(78)	(80)	(27)	(21)
Amortization of Transition Obligation	-	-	6	7
Amortization of Net Actuarial Loss	22	14	8	11
Net Periodic Benefit Cost	$ 35	$ 24	$ 28	$ 35

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Service Cost	$ 83	$ 78	$ 35	$ 32
Interest Cost	190	191	85	82
Expected Return on Plan Assets	(234)	(241)	(79)	(61)
Amortization of Transition Obligation	-	-	20	20

Amortization of Net Actuarial Loss	67	44	22	32
Net Periodic Benefit Cost	$ 106	$ 72	$ 83	$ 105

We made a $350 million voluntary contribution to the qualified pension trust in September 2010. This contribution is in addition to the $150 million contribution that we are making ratably throughout 2010. We made no contributions in 2009.

7. BUSINESS SEGMENTS

As outlined in our 2009 Annual Report, 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

- Χομμερχιαλ βαργινγ οπερατιονσ τηατ τρανσπορτ χοαλ ανδ δρψ βυλκ χομμοδιτιεσ πριμαριλψ ον τηε Οηιο, Ιλλινοισ ανδ λοωερ Μισσισσιππι Ριϖερ.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT.

The remainder of our 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.
- 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 settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the three and nine months ended September 30, 2010 and 2009 and balance sheet information as of September 30, 2010 and December 31, 2009. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended September 30, 2010						
Revenues from:						
External Customers	$ 3,876	$ 147	$ 41	$ -	$ -	$ 4,064
Other Operating Segments	31	7	-	3	(41)	-
Total Revenues	$ 3,907	$ 154	$ 41	$ 3	$ (41)	$ 4,064
Net Income	$ 541	$ 14	$ -	$ 2	$ -	$ 557

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended September 30, 2009						
Revenues from:						
External Customers	$ 3,364 (d)	$ 113	$ 68	$ 2	$ -	$ 3,547
Other Operating Segments	25 (d)	4	-	1	(30)	-
Total Revenues	$ 3,389	$ 117	$ 68	$ 3	$ (30)	$ 3,547
Income (Loss) Before Extraordinary Loss	$ 448	$ 10	$ 5	$ (17)	$ -	$ 446
Extraordinary Loss, Net of Tax	-	-	-	-	-	-
Net Income (Loss)	$ 448	$ 10	$ 5	$ (17)	$ -	$ 446

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Nine Months Ended September 30, 2010						
Revenues from:						
External Customers	$ 10,468	$ 395	$ 130	$ -	$ -	$ 10,993
Other Operating Segments	76	17	-	10	(103)	-
Total Revenues	$ 10,544	$ 412	$ 130	$ 10	$ (103)	$ 10,993

Net Income (Loss)	$	1,017	$	16	$	17	$	(10)	$	-	$	1,040

	Utility Operations		Nonutility Operations AEP River Operations		Generation and Marketing		All Other (a)		Reconciling Adjustments		Consolidated	
					(in millions)							
Nine Months Ended September 30, 2009												
Revenues from:												
External Customers	$	9,666 (d)	$	341	$	213	$	(13)	$	-	$	10,207
Other Operating Segments		46 (d)		13		6		28		(93)		-
Total Revenues	$	9,712	$	354	$	219	$	15	$	(93)	$	10,207
Income (Loss) Before Extraordinary Loss	$	1,121	$	22	$	33	$	(45)	$	-	$	1,131
Extraordinary Loss, Net of Tax		(5)		-		-		-		-		(5)
Net Income (Loss)	$	1,116	$	22	$	33	$	(45)	$	-	$	1,126

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		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)		
September 30, 2010						
Total Property, Plant and Equipment	$ 52,041	$ 542	$ 584	$ 10	$ (250)	$ 52,927
Accumulated Depreciation and Amortization	17,667	105	191	9	(43)	17,929
Total Property, Plant and Equipment - Net	$ 34,374	$ 437	$ 393	$ 1	$ (207)	$ 34,998
Total Assets	$ 47,964	$ 603	$ 898	$ 15,621	$ (15,194) (c)	$ 49,892

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)		
December 31, 2009						
Total Property, Plant and Equipment	$ 50,905	$ 436	$ 571	$ 10	$ (238)	$ 51,684
Accumulated Depreciation and Amortization	17,110	88	168	8	(34)	17,340
Total Property, Plant and Equipment - Net	$ 33,795	$ 348	$ 403	$ 2	$ (204)	$ 34,344
Total Assets	$ 46,930	$ 495	$ 779	$ 15,094	$ (14,950) (c)	$ 48,348

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- 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 settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(b) Includes eliminations due to an intercompany capital lease.

(c) 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.

(d) 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 was offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of $(113) thousand and $(6) million for the three and nine months ended September 30, 2009, respectively. The Generation and Marketing segment also reported these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are 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, credit risk and to a lesser extent foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

Our strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact.

Risk Management Strategies

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into power, coal, natural gas, interest rate and to a lesser degree heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of September 30, 2010 and December 31, 2009:

Notional Volume of Derivative Instruments

	Volume September 30, 2010 (in millions)		Volume December 31, 2009 (in millions)		Unit of Measure
Commodity:					
Power		789		589	MWHs
Coal		71		60	Tons
Natural Gas		110		127	MMBtus
Heating Oil and Gasoline		7		6	Gallons
Interest Rate	$	180	$	216	USD
Interest Rate and Foreign Currency	$	664	$	83	USD

Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain 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. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. We do not hedge all fuel price risk. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

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 as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when 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. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet 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, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. 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 may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. 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 September 30, 2010 and December 31, 2009 balance sheets, we netted $20 million and $12 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $228 million and $98 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our Condensed Consolidated Balance Sheets as of September 30, 2010 and December 31, 2009:

Fair Value of Derivative Instruments
September 30, 2010

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)(c)	Other (a) (b)	Total
			(in millions)		
Current Risk Management Assets	$ 1,229	$ 16	$ 4	$ (970)	$ 279
Long-term Risk Management Assets	835	10	3	(360)	488
Total Assets	2,064	26	7	(1,330)	767
Current Risk Management Liabilities	1,167	19	3	(1,065)	124
Long-term Risk Management Liabilities	687	4	3	(527)	167
Total Liabilities	1,854	23	6	(1,592)	291
Total MTM Derivative Contract Net Assets (Liabilities)	$ 210	$ 3	$ 1	$ 262	$ 476

Fair Value of Derivative Instruments
December 31, 2009

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in millions)		
Current Risk Management Assets	$ 1,078	$ 13	$ -	$ (831)	$ 260
Long-term Risk Management Assets	614	-	-	(271)	343
Total Assets	1,692	13	-	(1,102)	603
Current Risk Management Liabilities	997	17	3	(897)	120
	442	-	2	(316)	128

Long-term Risk Management Liabilities					
Total Liabilities	1,439	17	5	(1,213)	248
Total MTM Derivative Contract Net Assets (Liabilities)	$ 253	$ (4)	$ (5)	$ 111	$ 355

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Consolidated Balance Sheet on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

(c) At September 30, 2010, Risk Management Assets included $7 million related to fair value hedging strategies while the remainder related to cash flow hedging strategies. At December 31, 2009, we only employed cash flow hedging strategies.

The table below presents our activity of derivative risk management contracts for the three and nine months ended September 30, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2010 and 2009

Location of Gain (Loss)	2010		2009	
		(in millions)		
Utility Operations Revenue	$	24	$	25
Other Revenue		(4)		1
Regulatory Assets (a)		(6)		(7)
Regulatory Liabilities (a)		7		24
Total Gain (Loss) on Risk Management Contracts	$	21	$	43

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2010 and 2009

Location of Gain (Loss)	2010		2009	
		(in millions)		
Utility Operations Revenue	$	69	$	124
Other Revenue		5		19
Regulatory Assets (a)		(9)		(17)
Regulatory Liabilities (a)		34		33
Total Gain (Loss) on Risk Management Contracts	$	99	$	159

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for “Derivatives and Hedging.” Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Condensed 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 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 on the Condensed 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 Condensed Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.”

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Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our Condensed Consolidated Statements of Income. During the three and nine months ended September 30, 2010, we recognized gains of $3 million and $7 million, respectively, on our hedging instruments with offsetting losses of $3 million and $7 million, respectively, on our long-term debt. During the three and nine months ended September 30, 2010, no hedge ineffectiveness was recognized. During the three and nine months ended September 30, 2009, we did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows 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 Condensed 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).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas, and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Condensed Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Condensed Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2010 and 2009, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Condensed Consolidated Statements of Income. During the three and nine months ended September 30, 2010 and 2009, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2010 and 2009, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Depreciation and Amortization expense on our Condensed Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2010 and 2009, we designated foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2010 and 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2010

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of June 30, 2010	$ 2	$ (15)	$ (13)
Changes in Fair Value Recognized in AOCI	(2)	(1)	(3)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Utility Operations Revenue	1	-	1
Other Revenue	(1)	-	(1)
Purchased Electricity for Resale	1	-	1
Interest Expense	-	1	1
Regulatory Assets (a)	1	-	1
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2010	$ 2	$ (15)	$ (13)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2009

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of June 30, 2009	$ 6	$ (11)	$ (5)
Changes in Fair Value Recognized in AOCI	(6)	(4)	(10)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(7)	-	(7)
Other Revenue	(5)	-	(5)
Purchased Electricity for Resale	10	-	10
Interest Expense	-	1	1
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	(3)	-	(3)
Balance in AOCI as of September 30, 2009	$ (3)	$ (14)	$ (17)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	2	(5)	(3)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Utility Operations Revenue	1	-	1
Other Revenue	(4)	-	(4)
Purchased Electricity for Resale	3	-	3
Interest Expense	-	3	3
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2010	$ 2	$ (15)	$ (13)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2008	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(9)	11	2
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(13)	-	(13)
Other Revenue	(11)	-	(11)
Purchased Electricity for Resale	24	-	24
Interest Expense	-	4	4
Regulatory Assets (a)	5	-	5
Regulatory Liabilities (a)	(6)	-	(6)
Balance in AOCI as of September 30, 2009	$ (3)	$ (14)	$ (17)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheet.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets at September 30, 2010 and December 31, 2009 were:

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
September 30, 2010

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 16	$ -	$ 16
Hedging Liabilities (a)	(13)	(6)	(19)
AOCI Gain (Loss) Net of Tax	2	(15)	(13)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(1)	(4)	(5)

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
December 31, 2009

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 8	$ -	$ 8
Hedging Liabilities (a)	(12)	(5)	(17)
AOCI Gain (Loss) Net of Tax	(2)	(13)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(2)	(4)	(6)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Condensed Consolidated Balance Sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of September 30, 2010, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 39 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We use 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 exceeds our 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 allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the 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. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We do not anticipate a downgrade below investment grade. The following table represents our aggregate fair value of such derivative contracts, the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$23	$10
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	55	34
Amount Attributable to RTO and ISO Activities	54	29

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding debt in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. We do not anticipate a non-performance event under these provisions. The following table represents the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, the amount this exposure has been reduced by cash collateral we have posted and if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of September 30, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$568	$567
Amount of Cash Collateral Posted	146	15
Additional Settlement Liability if Cross Default Provision is Triggered	241	199

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" 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). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and 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 as Level 3.

We utilize our trustee’s external pricing service in our estimate of the fair value of the underlying investments held in the nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee’s operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	United States Government	Corporate Debt	State and Local Government
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, 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 as of September 30, 2010 and December 31, 2009 are summarized in the following table:

	September 30, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,281	$ 19,641	$ 17,498	$ 18,479

Fair Value Measurements of Other Temporary Investments

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

The following is a summary of Other Temporary Investments:

	September 30, 2010			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 160	$ -	$ -	$ 160
Fixed Income Securities:				
Mutual Funds	69	1	-	70
Variable Rate Demand Notes	73	-	-	73
Equity Securities - Mutual Funds	18	5	-	23
Total Other Temporary Investments	$ 320	$ 6	$ -	$ 326

	December 31, 2009			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 223	$ -	$ -	$ 223
Fixed Income Securities:				
Mutual Funds	57	-	-	57
Variable Rate Demand Notes	45	-	-	45
Equity Securities:				
Domestic	1	15	-	16
Mutual Funds	18	4	-	22
Total Other Temporary Investments	$ 344	$ 19	$ -	$ 363

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

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the three and nine months ended September 30, 2010 and 2009:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Proceeds From Investment Sales	$ 133	$ -	$ 390	$ -
Purchases of Investments	192	1	413	2
Gross Realized Gains on Investment Sales	-	-	16	-
Gross Realized Losses on Investment Sales	-	-	-	-

In June 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell captive insurance company. At September 30, 2010, the fair value of fixed income securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes. Mutual funds may be sold and do not contain maturity dates for an individual investment holder.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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.
- Target asset allocation is 50% fixed income and 50% equity securities.

We maintain trust records 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 trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether the investor has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment, among other things, is based on whether the investor has the ability and intent to hold the investment to recover its value. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. 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 jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at September 30, 2010 and December 31, 2009:

	September 30, 2010			December 31, 2009		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 30	$ -	$ -	$ 14	$ -	$ -
Fixed Income Securities:						
United States Government	489	41	(1)	401	13	(4)
Corporate Debt	65	5	(2)	57	5	(2)
State and Local Government	308	(7)	-	369	8	1
Subtotal Fixed Income Securities	862	39	(3)	827	26	(5)
Equity Securities - Domestic	574	124	(123)	551	234	(119)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,466	$ 163	$ (126)	$ 1,392	$ 260	$ (124)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2010 and 2009:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Proceeds From Investment Sales	$ 495	$ 113	$ 1,087	$ 524
Purchases of Investments	512	129	1,129	571
Gross Realized Gains on Investment Sales	1	1	7	10
Gross Realized Losses on Investment Sales	-	-	-	1

The adjusted cost of debt securities was $823 million and $801 million as of September 30, 2010 and December 31, 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at September 30, 2010 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 13
1 year – 5 years	346
5 years – 10 years	267
After 10 years	236
Total	$ 862

74

Fair Value Measurements of Financial Assets and Liabilities

The following tables set 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 September 30, 2010 and December 31, 2009. As required by the accounting guidance for “Fair Value Measurements and Disclosures,” 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. There have not been any significant changes in AEP’s valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2010