AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 28, 2011

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, 2011
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	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	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	X	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 27, 2011
American Electric Power Company, Inc.	482,912,247 ($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 OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2011

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., a holding company.
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 AEP Power 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.
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.
BOA	Bank of America Corporation.
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, a transition charge applied to TCC's transmission and distribution rates for stranded costs and other true-up amounts as required by the Texas Restructuring Legislation.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC, variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
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 regional transmission organization.
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.
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.

Term	Meaning
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.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
NEIL	Nuclear Electric Insurance Limited insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks.
NOx	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
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.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
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, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SIA	

	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.

Term	Meaning
SO2	Sulfur Dioxide.
SPP	Southwest Power Pool regional transmission organization.
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 is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
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. Many forward-looking statements appear in "Item 7 – Management's Financial Discussion and Analysis" of the 2010 Annual Report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. 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 lines and 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 nuclear generation, 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 and related assets.
- 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.
- 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.
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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 our debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation 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, captive insurance entity 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.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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 DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Customer Demand

In comparison to 2010 for both the quarter-to-date and year-to-date periods, cooling degree days in 2011 were up 13% and 19%, respectively, in our western region and down 2% and 7%, respectively, in our eastern region. While cooling degree days in our eastern region were down slightly in comparison to 2010, they were significantly higher than normal. Our non-weather residential and commercial sales remained relatively flat in comparison to 2010. Industrial sales are up just over 5% for the quarter-to-date and year-to-date periods, reflecting a significant increase in production from Ormet, a large aluminum company, and lesser increases from several other industrial customers, reflecting an increase in production at several of our metals and refinery customers. Commercial margins decreased 5% for the year-to-date period primarily due to the loss of retail customers in Ohio. See "Ohio Customer Choice" section below.

Texas Restructuring Appeals

In July 2011, the Supreme Court of Texas overturned a 2006 PUCT order that had denied recovery of capacity auction true-up amounts related to TCC securitized net recoverable stranded generation cost. Based upon the Supreme Court of Texas' opinion, TCC recorded $421 million of pretax income ($273 million, net of tax) in Extraordinary Item, Net of Tax on the condensed statements of income in the third quarter of 2011.

Also in the third quarter of 2011, TCC recorded $261 million in pretax Carrying Costs Income on the condensed statements of income related to the debt component of carrying costs for the period from January 2002 through September 2011. This carrying costs income represents previously unrecorded earnings associated with restructuring in Texas since 2002. The total regulatory asset related to the capacity auction true-up as of September 30, 2011 was $682 million. In October 2011, TCC filed with the PUCT requesting a final determination of the amount to be securitized. In its filing, TCC presented three alternative carrying cost calculations through March 2012, the anticipated securitization date, where the debt and equity component of carrying costs ranged from $396 million to $756 million, including $280 million to $444 million for the debt component of carrying costs. The final amount of carrying costs will be determined by the PUCT and could vary from the calculations presented by TCC. TCC plans to recognize debt carrying costs income prior to securitization and equity carrying costs income will be recognized as collected over the life of the securitization. A PUCT hearing is scheduled for November 2011. See "Texas Restructuring Appeals" section of Note 3.

Regulatory Activity

Ohio 2009 – 2011 ESPs

In April 2011, the Supreme Court of Ohio issued an opinion addressing the aspects of the PUCO's 2009 decision that were challenged and remanded certain issues back to the PUCO. In October 2011, the PUCO issued an order in the remand proceeding. The order required CSPCo and OPCo to refund POLR charges which were collected subject to refund since June 2011. As a result, in the third quarter of 2011, CSPCo and OPCo recorded pretax refund provisions of $34 million and $9 million, respectively, on the condensed statements of income.

In July 2011, CSPCo and OPCo filed their 2010 SEET filings with the PUCO. Based upon the approach in the PUCO 2009 order, management does not currently believe that CSPCo or OPCo will have any significantly excessive earnings. In October 2011, the Ohio Consumers' Counsel and the Ohio Energy Group filed testimony that recommended CSPCo refund up to $41 million of its 2010 earnings. Also in October 2011, the PUCO staff filed testimony that recommended CSPCo refund $21 million of its 2010 earnings. See “Ohio Electric Security Plan Filings” section of Note 3.

1

Ohio January 2012 – May 2016 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation. In September 2011, a stipulation agreement was filed with the PUCO which involved various issues pending before the PUCO, including the approval of the CSPCo/OPCo merger and the recovery of deferred fuel until securitized. Under the stipulation agreement, rates would be effective with the first billing cycle of January 2012 through the last billing cycle of May 2016. Prior to June 2015, CSPCo's and OPCo's SSO customers continue to pay the tariff rate for non-fuel generation and the fuel adjustment clause. Beginning in June 2015, CSPCo and OPCo will use results from a competitive bidding process performed prior to January 2015 to meet their SSO obligation through May 2016. The stipulation agreement proposed a corporate separation plan of CSPCo's and OPCo's generation assets to complete the transition to a fully competitive generation market by June 2015. In addition, to further develop customer choice and facilitate the transition to market generation pricing, CSPCo and OPCo will provide 21% of their generation capacity in 2012, 29% to 31% of their generation capacity in 2013 and 41% of their generation capacity beginning in 2014 through May 2015 to competitive retail suppliers at a charge based on the Reliability Pricing Model auction-clearing prices and the remainder at a discounted cost-based price.

The stipulation agreement also proposed a termination or modification of the Interconnection Agreement. Finally, the stipulation agreement provides for certain CSPCo and OPCo contingent contributions and established a Distribution Investment Rider beginning January 2012 through May 2015 to recover post-2000 distribution investment with certain limitations. See "Ohio Electric Security Plan Filings," "Proposed CSPCo and OPCo Merger" and "Possible Termination of the Interconnection Agreement" sections of Note 3.

Ohio Distribution Base Rate Case

In February 2011, CSPCo and OPCo filed with the PUCO for annual increases in distribution rates of $34 million and $60 million, respectively. The requested increase is based upon an 11.15% return on common equity to be effective January 2012. In addition to the annual increases, CSPCo and OPCo requested recovery of the projected December 31, 2012 balances of certain distribution regulatory assets of $216 million and $159 million, respectively, including carrying costs, to be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013. The PUCO staff filed testimony that recommended a rate reduction for CSPCo in the range of $2 million to $10 million and a rate increase for OPCo in the range of $23 million to $32 million. In addition, the PUCO staff recommended recovery of the deferred distribution regulatory assets subject to a review of the carrying costs. A decision from the PUCO is expected in the fourth quarter of 2011. See "2011 Ohio Distribution Base Rate Case" section of Note 3.

Virginia Regulatory Activity

In March 2011, APCo filed a generation and distribution base rate request with the Virginia SCC to increase annual base rates by $126 million based upon an 11.65% return on common equity to be effective no later than February 2012. The return on common equity includes a requested 0.5% renewable portfolio standards incentive as allowed by law. APCo proposed to mitigate the requested base rate increase by $51 million by maintaining current depreciation rates until the next biennial filing. If approved, APCo's net base rate increase would be $75 million. In August 2011, the Virginia Attorney General and the Virginia SCC staff filed testimony recommending no increase in annual base rates and a $31 million increase in annual base rates, respectively. Hearings were held in September 2011. A decision from the Virginia SCC is pending. See "2011 Virginia Biennial Base Rate Case" section of Note 3.

West Virginia Regulatory Activity

In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $51 million based upon a 10% return on common equity. The approved settlement agreement also resulted in a pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility in the first quarter of 2011. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and allowed APCo and WPCo to defer and amortize $15 million of previously expensed costs related to the 2010 cost reduction initiatives, each over a period of seven years. See "2010 West Virginia Base Rate Case" section of Note 3.

Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense. I&M plans to request an interim rate increase, subject to refund, for the portion of the $25 million that, among other things, excludes the depreciation rate changes and other regulatory amortizations. I&M plans to propose the interim rate increase be effective in January 2012.

Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As a result, in comparison to the third quarter of 2010 and the first nine months of 2010, we lost approximately $41 million and $94 million, respectively, of generation and transmission related gross margin. We are recovering a portion of lost margins through collection of transmission revenues from competitive CRES providers, off-system sales and new revenues from our CRES provider. Our CRES provider targets retail customers in Ohio, both within and outside of our retail service territory.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal 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. SWEPCo’s share of construction costs is currently estimated to be $1.3 billion, excluding AFUDC, plus an additional $129 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo’s original application to build the Turk Plant. In June 2010, the APSC issued an order which reversed and set aside the previously granted Certificate of Environmental Compatibility and Public Need. Various proceedings are pending that challenge the Turk Plant’s construction and its approved wetlands and air permits. In 2010, the motions for preliminary injunction were partially granted by the Federal District Court for the Western District of Arkansas. 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 portions of two transmission lines. In July 2011, the U.S. Eighth Circuit Court of Appeals affirmed the preliminary injunction and remanded the case to the district court. Management is unable to predict the timing or the outcome related to this remand proceeding.

In August 2011, a joint stipulation of dismissal was approved by the Federal District Court for the Western District of Arkansas that resolved all pending matters between SWEPCo, the Hempstead County Hunting Club (Hunting Club) and several other parties. As a result, the Hunting Club’s challenge to the U.S. Army Corps of Engineers permit in the Federal District Court for the Western District of Arkansas was dismissed and the Hunting Club’s appeal of the air permit was withdrawn. Additional judicial and administrative proceedings were terminated. The Sierra Club and the Audubon Society challenges to the wetlands and air permits remain pending.

In October 2011, the Sierra Club, the National Audubon Society and Audubon Arkansas filed a complaint with the APSC requesting that construction of the Turk Plant be halted until SWEPCo or the Arkansas Electric Cooperative Corporation obtain either a Certificate of Environmental Compatibility and Public Need, or SWEPCo obtains a

Certificate of Convenience and Necessity and performs an Environmental Impact Statement on associated gas facilities. Management believes the complaint is without merit and intends to vigorously defend against the complaint.

3

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. See "Turk Plant" section of Note 3.

Cook Plant

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 $408 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. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1. 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 "Michigan 2009 and 2010 Power Supply Cost Recovery Reconciliations" section of Note 3 and "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, we expect the Nuclear Regulatory Commission and possibly Congress to review safety procedures and requirements for nuclear generating facilities. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. We are unable to predict the impact of potential future regulation of nuclear facilities.

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 predict the eventual resolution, timing or amount of any loss, fine or penalty. 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" in the 2010 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, financial condition and cash flows.

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 SO2, NOx, PM and hazardous air pollutants from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

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 CO2 emissions to address concerns about global climate change. AEP, various industry groups, affected states and other parties have urged the Federal EPA to conduct additional analysis and either postpone the effective date or extend the time frame for compliance with some of these future requirements. The U.S. House of Representatives passed legislation called the Transparency in Regulatory Analysis of Impacts on the Nation (the TRAIN Act) that would delay implementation of certain Federal EPA rules to facilitate a comprehensive analysis of their impacts. The Senate is considering similar legislation. We believe that further analysis and better coordination of these future environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

See a complete discussion of these matters in the "Environmental Issues" section of "Management's Financial Discussion and Analysis" in the 2010 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. We should be able to recover certain of these expenditures through market prices in deregulated jurisdictions. If not, the costs of environmental compliance could adversely affect future net income, cash flows and possibly financial condition.

Update to Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2011, the AEP System had a total generating capacity of nearly 38,000 MWs, of which 23,900 MWs are coal-fired. In the second quarter of 2011, we refined the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon the updated estimates, investment to meet these proposed requirements ranges from approximately $6 billion to $8 billion between 2012 and 2020. These amounts include investments to convert 1,070 MWs of coal generation to 932 MWs of natural gas capacity and build approximately 580 MWs of natural gas-fired generation.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose standards more stringent than the proposed rules, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon our continuing evaluation, we may retire the following plants or units of plants before 2015:

Company	Plant Name and Unit	Generating Capacity (in MWs)
KPCo	Big Sandy Plant, Unit 1	278
APCo	Clinch River Plant, Unit 3	235
CSPCo	Conesville Plant, Unit 3	165
APCo	Glen Lyn Plant	335
OPCo	Kammer Plant	630
APCo	Kanawha River Plant	400
OPCo	Muskingum River Plant, Units 1-4	840
APCo/OPCo	Philip Sporn Plant	1,050
CSPCo	Picway Plant	100
I&M	Tanners Creek Plant, Units 1-3	495
SWEPCo	Welsh Plant, Unit 2	528
	Total	5,056

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. CSPCo owns 12.5% (54 MWs) of one unit at that station.

Plans for and the timing of conversion of some of our coal units to natural gas, installing emission control equipment on other units and closure of existing units will be impacted by changes in emission requirements and demand for power. We are completing construction of the Turk and Dresden Plants. Recovery of the remaining investments in facilities that we may close and cost of new equipment and converted facilities will be subject to regulatory approval.

Cross-State Air Pollution Rule (formerly the Clean Air Act 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 SO2 and NOx emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the proposed Clean Air Act Transport Rule (Transport Rule) was assigned an allowance budget for SO2 and/or NOx. Limited interstate trading was allowed on a sub-regional basis and intrastate trading was allowed among generating units. Our western states (Arkansas, Oklahoma and Texas) would be subject to only the seasonal NOx program, with new limits that were proposed to take effect in 2012. The remainder of the states in which we operate would have been subject to seasonal and annual NOx programs and an annual SO2 emissions reduction program that takes effect in two phases. The first phase was to be effective in 2012 and more stringent SO2 emission reductions were proposed to take effect in 2014 in certain states. The SO2 and NOx programs rely on newly-created allowances rather than relying on the CAIR NOx allowances or the Title IV Acid Rain Program allowances used in CAIR.

In July 2011, the Federal EPA released the final rule, renamed the Cross-State Air Pollution Rule (CSAP Rule). Like the proposed Transport Rule, the CSAP Rule relies on newly-created SO2 and NOx allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis beginning in 2012. Arkansas and Louisiana are subject only to the seasonal NOx program in the final rule. A proposed supplemental rule would include Oklahoma in the seasonal NOx program. Texas is now subject to the annual programs for SO2 and NOx in addition to the seasonal NOx program. The annual SO2 allowance budgets in Indiana, Ohio and West Virginia have been reduced significantly in the final rule.

In October 2011, the Federal EPA released a supplemental proposed rule revising portions of the final CSAP Rule. The proposed rule would correct errors in unit-specific assumptions and make available additional allowances in ten states, including Louisiana and Texas, and provide additional allowances for the new unit set aside in Arkansas. In addition, the proposed rule would make the allowance trading assurance provisions which restrict interstate trading of allowances effective January 1, 2014 instead of January 1, 2012.

The time frames and stringency of the required 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. The compliance plan described above was based on the requirements of the proposed Transport Rule. The more stringent requirements included in the final CSAP Rule could cause further unit curtailments, increase capital requirements, constrain operations, decrease reliability and unfavorably impact financial condition if the increased costs are not recovered in rates or market prices.

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 by the D.C. Circuit Court of Appeals in 2008. In response, the Federal EPA has been developing a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal, on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance is required within three years of the effective date of the final rule, which is expected in December 2011 per the Federal EPA’s settlement agreement with several environmental groups. A one-year extension may be available if the extension is necessary for the installation of controls. In October 2011, various intervenors filed a motion to extend the deadline by which the Federal EPA is required to finalize the HAPs rule for one year, to November 2012. The motion was supported by 25 states’ attorneys general. A joint request of the Federal EPA and the plaintiffs to extend the deadline for finalizing the rule for 30 days, to December 16, 2011, was granted.

6

We submitted comments on the proposed rule and urged 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. We have older coal units for which it may be economically inefficient to install scrubbers or other environmental controls. Several of these units are included in our current list of potential plant closures discussed above.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze state implementation plan (SIP) submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA is proposing to approve all of the NOx control measures in the SIP and disapprove the SO2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA is proposing a federal implementation plan (FIP) that would require these units to install technology capable of reducing SO2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The State of Oklahoma filed suit in Federal District Court in the Western District of Oklahoma seeking to enjoin the Federal EPA from taking final action on the FIP without allowing the state to first respond to the deficiencies identified for the first time in the proposed disapproval of the SIP. Motions for preliminary relief are pending. PSO submitted comments on the proposed action demonstrating that the cost-effectiveness calculations performed by the Federal EPA were unsound, challenging the period for compliance with the final rule and showing that the visibility improvements secured by the proposed SIP were significant and cost-effective. Final action on the proposal is required to be taken by December 14, 2011 under a consent decree between the Federal EPA and certain environmental advocacy groups.

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 proposal would impose federal hazardous waste disposal and management standards on these materials and another 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. In October 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. Comments are due in November 2011.

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 $3.9 billion including AFUDC for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant’s cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment

7

standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. We submitted comments on the proposal in July and August 2011.

Global Warming

While comprehensive economy-wide regulation of CO2 emissions might be mandated through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO2 emissions from stationary sources will be subject to regulation under the CAA 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 through the issuance of final federal rules, state implementation plan calls and federal implementation plans. 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 and announced a settlement agreement to issue proposed new source performance standards for utility boilers that would be applicable for both new and existing utility boilers. It is not possible at this time to estimate the costs of compliance with these new standards, but they may be material.

Our fossil fuel-fired generating units are very large sources of CO2 emissions. If substantial CO2 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 CO2 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 and natural gas based 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 CO2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Michigan, Ohio, 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 CO2 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 CO2 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 2010 Form 10-K under the headings entitled “Business – General – Environmental and Other Matters – Global Warming” and “Management’s Financial Discussion and Analysis.”

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 and, to a lesser extent, Ohio in PJM and MISO.

The table below presents our consolidated Income Before Extraordinary Item by segment for the three and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
				(in millions)				
Utility Operations	$	642	$	541	$	1,376	$	1,017
AEP River Operations		17		14		23		16
Generation and Marketing		8		-		20		17
All Other (a)		(10)		2		(54)		(10)
Income Before Extraordinary Item	$	657	$	557	$	1,365	$	1,040

(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 expire in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ends in the fourth quarter of 2011.

AEP CONSOLIDATED

Third Quarter of 2011 Compared to Third Quarter of 2010

Income Before Extraordinary Item increased from $557 million in 2010 to $657 million in 2011 primarily due to:

- An increase in carrying costs income due to the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
- Successful rate proceedings in our various jurisdictions.
- An increase in weather-related usage.

These increases were partially offset by:

- Various Ohio adjustments in the third quarter of 2011, including the refund provision for POLR charges collected from customers, the impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5 and the write-off of allocated Front-End Engineering and Design (FEED) study costs related to the Mountaineer Carbon Capture Project.
- The loss of retail customers in Ohio to various competitive retail electric service providers.

Average basic shares outstanding increased from 480 million in 2010 to 482 million in 2011.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Income Before Extraordinary Item increased from $1,040 million in 2010 to $1,365 million in 2011 primarily due to the following:

· A decrease in expenses as a result of the second quarter 2010 cost reduction initiatives.
· An increase in carrying costs income due to the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
· Successful rate proceedings in our various jurisdictions.
· The unfavorable 2010 tax treatment associated with future reimbursement of Medicare Part D prescription drug benefits.

These increases were partially offset by:

· Various Ohio adjustments in the third quarter of 2011, including the refund provision for POLR charges collected from customers, the write-off of allocated FEED study costs related to the Mountaineer Carbon Capture Project and the impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
· A net-of-tax loss related to the first quarter of 2011 settlement of litigation with BOA and Enron.
· The loss of retail customers in Ohio to various competitive retail electric service providers.

Average basic shares outstanding increased from 479 million in 2010 to 482 million in 2011. Actual shares outstanding were 483 million as of September 30, 2011.

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 total 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,	
	2011	2010	2011	2010
	(in millions)			
Revenues	$ 4,074	$ 3,907	$ 10,987	$ 10,544
Fuel and Purchased Power	1,609	1,427	4,136	3,784
Gross Margin	2,465	2,480	6,851	6,760
Other Operation and Maintenance	882	849	2,587	2,798
Asset Impairments and Other Related Charges	90	-	90	-
Depreciation and Amortization	435	413	1,226	1,205
Taxes Other Than Income Taxes	210	208	618	613
Operating Income	848	1,010	2,330	2,144
Interest and Investment Income	18	2	21	6
Carrying Costs Income	290	17	323	51
Allowance for Equity Funds Used During Construction	26	17	69	60

Interest Expense	(223)	(238)	(682)	(710)
Income Before Income Tax Expense and Equity Earnings	959	808	2,061	1,551
Equity Earnings of Unconsolidated Subsidiaries	7	3	19	7
Income Tax Expense	324	270	704	541
Income Before Extraordinary Item	$ 642	$ 541	$ 1,376	$ 1,017

Summary of KWH Energy Sales for Utility Operations

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions of KWHs)			
Retail:				
Residential	18,238	17,817	48,690	48,250
Commercial	14,274	14,032	38,833	38,508
Industrial	15,206	14,460	44,688	42,503
Miscellaneous	854	832	2,354	2,328
Total Retail (a)	48,572	47,141	134,565	131,589
Wholesale	13,164	10,689	32,532	25,846
Total KWHs	61,736	57,830	167,097	157,435

(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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in degree days)			
Eastern Region				
Actual - Heating (a)	6	1	1,995	1,976
Normal - Heating (b)	7	7	1,914	1,918
Actual - Cooling (c)	838	859	1,209	1,294
Normal - Cooling (b)	700	691	999	984
Western Region				
Actual - Heating (a)	-	-	702	764
Normal - Heating (b)	1	1	601	596
Actual - Cooling (d)	1,669	1,471	2,813	2,357
Normal - Cooling (b)	1,359	1,353	2,179	2,168

(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.

11

Third Quarter of 2011 Compared to Third Quarter of 2010

Reconciliation of Third Quarter of 2010 to Third Quarter of 2011
Income from Utility Operations before Extraordinary Item
(in millions)

Third Quarter of 2010	$	541	
Changes in Gross Margin:			
Retail Margins		(19	)
Off-system Sales		(1	)
Transmission Revenues		14	
Other Revenues		(9	)
Total Change in Gross Margin		(15	)
Changes in Expenses and Other:			
Other Operation and Maintenance		(33	)
Asset Impairments and Other Related Charges		(90	)
Depreciation and Amortization		(22	)
Taxes Other Than Income Taxes		(2	)
Interest and Investment Income		16	
Carrying Costs Income		273	
Allowance for Equity Funds Used During Construction		9	
Interest Expense		15	
Equity Earnings of Unconsolidated Subsidiaries		4	
Total Change in Expenses and Other		170	
Income Tax Expense		(54	)
Third Quarter of 2011	$	642	

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

· Retail Margins decreased $19 million primarily due to the following:
  · A $41 million decrease attributable to Ohio customers switching to alternative competitive retail electric service (CRES) providers.
  · A $33 million refund provision for CSPCo POLR charges as a result of the October 2011 PUCO remand order.
  · A $29 million increase in other variable electric generation expenses.
  · A $23 million decrease in rate related margins for APCo due to the expiration of E&R cost recovery in Virginia.

  These decreases were partially offset by:
  · Successful rate proceedings in our service territories which include:
    · A $57 million rate increase in Ohio.
    · A $22 million rate increase for APCo.
    · A $10 million rate increase for I&M.
    · A $3 million rate increase for SWEPCo.
    ·

For the rate increases described above, $41 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.

- A $14 million increase in weather-related usage primarily due to a 13% increase in cooling degree days in our western region.
- A $5 million increase in revenues related to TCC's securitization. This increase is offset by an increase in Depreciation and Amortization expenses.

- Transmission Revenues increased $14 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.
- Other Revenues decreased $9 million primarily due to lower amortization of deferred gains.

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

- Other Operation and Maintenance expenses increased $33 million primarily due to:
  - A $9 million increase due to the third quarter 2011 write-off of Ohio allocated FEED study costs related to the Mountaineer Carbon Capture Project.
  - A $9 million increase in plant outage expenses and other plant operating and maintenance expenses.
  - An $8 million increase in storm-related expenses.
  - An $8 million increase in transmission-related expenses.
  - A $4 million increase in demand side management expenses, energy efficiency program expenses and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.

  These increases were partially offset by:
  - A $6 million decrease associated with the favorable resolution of an I&M contingency.
- Asset Impairments and Other Related Charges includes the third quarter 2011 plant impairments of Sporn Unit 5 ($48 million) and the FGD project at Muskingum River Unit 5 ($42 million).
- Depreciation and Amortization expenses increased $22 million primarily due to the following:
  - A $19 million increase for OPCo due to the amortization of debt and equity carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which required the POLR refund to be applied against deferred fuel balances. The equity amortization was partially offset by amounts recognized in Carrying Costs Income.
  - A $10 million increase in depreciation and amortization for TCC primarily due to increased amortization of TCC's Securitized Transition Asset. This increase is offset by an increase in revenues within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - An $8 million decrease in depreciation and amortization for APCo primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia.
- Interest and Investment Income increased $16 million primarily due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- Carrying Costs Income increased $273 million primarily due to the following:
  - A $261 million increase in carrying costs income due to the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
  - A $10 million increase due to the recognition of equity carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which required the POLR refund to be applied against any deferred fuel balances. The equity carrying costs income was offset by amounts in Depreciation and Amortization discussed above.
- Allowance for Equity Funds Used During Construction increased $9 million primarily due to construction of the Turk and Dresden Plants and various environmental upgrades.
- Interest Expense decreased $15 million primarily due to lower outstanding debt balances.
- Equity Earnings of Unconsolidated Subsidiaries increased $4 million primarily due to an increase in transmission investments by ETT.
- Income Tax Expense increased $54 million primarily due to an increase in pre-tax book income.

13

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Reconciliation of Nine Months Ended September 30, 2010 to Nine Months Ended
September 30, 2011
Income from Utility Operations before Extraordinary Item
(in millions)

Nine Months Ended September 30, 2010	$	1,017
Changes in Gross Margin:		
Retail Margins		8
Off-system Sales		49
Transmission Revenues		34
Total Change in Gross Margin		91
Changes in Expenses and Other:		
Other Operation and Maintenance		211
Asset Impairments and Other Related Charges		(90)
Depreciation and Amortization		(21)
Taxes Other Than Income Taxes		(5)
Interest and Investment Income		15
Carrying Costs Income		272
Allowance for Equity Funds Used During Construction		9
Interest Expense		28
Equity Earnings of Unconsolidated Subsidiaries		12
Total Change in Expenses and Other		431
Income Tax Expense		(163)
Nine Months Ended September 30, 2011	$	1,376

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 $8 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $90 million rate increase in Ohio.
    - A $49 million rate increase for APCo.
    - A $32 million rate increase for KPCo.
    - A $25 million rate increase for I&M.
    - A $23 million rate increase for SWEPCo.
    - For the rate increases described above, $54 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.
  - A $32 million increase in weather-related usage in our western region primarily due to a 19% increase in cooling degree days.
  -

A $5 million increase related to TCC's Securitized Transition Asset. This increase is offset by an increase in Depreciation and Amortization expenses.

These increases were partially offset by:

- A $94 million decrease attributable to Ohio customers switching to alternative CRES providers.
- A $60 million decrease in rate related margins for APCo due to the expiration of E&R cost recovery in Virginia.
- A $37 million increase in other variable electric generation expenses.
- A $33 million refund provision for CSPCo POLR charges as a result of the October 2011 PUCO remand order.
- A $32 million decrease in weather-related usage in our eastern region primarily due to a 7% decrease in cooling degree days.

- Margins from Off-system Sales increased $49 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.

- Transmission Revenues increased $34 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.

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

- Other Operation and Maintenance expenses decreased $211 million primarily due to the following:
  - A $275 million decrease due to expenses related to the cost reduction initiatives recorded in the second quarter of 2010.
  - A $54 million decrease due to the second quarter 2010 write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.
  - A $33 million decrease due to the first quarter 2011 deferral of 2010 costs related to storms and our cost reduction initiatives as allowed by the WVPSC.
  - A $31 million decrease in administrative and general expenses primarily due to a decrease in fringe benefit expenses.
  - An $11 million gain on the sale of land.

  These decreases were partially offset by:
  - A $49 million increase in demand side management, energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $41 million increase due to the first quarter 2011 write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $36 million increase in storm-related expenses.
  - A $36 million increase in plant outage and other plant operating and maintenance expenses.
  - A $25 million increase due to the second quarter 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
  - A $9 million increase due to the third quarter 2011 write-off of Ohio allocated FEED study costs related to the Mountaineer Carbon Capture Project.
- Asset Impairments and Other Related Charges includes the third quarter 2011 plant impairments of Sporn Unit 5 ($48 million) and the FGD project at Muskingum River Unit 5 ($42 million).
- Depreciation and Amortization expenses increased $21 million primarily due to the following:
  - A $19 million increase for OPCo due to the amortization of debt and equity carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which required the POLR refund to be applied against deferred fuel balances. The equity amortization was partially offset by amounts recognized in Carrying Costs Income as discussed below.
  - A $15 million increase in depreciation and amortization for TCC primarily due to increased amortization of TCC's Securitized Transition Asset. This increase is offset by an increase in revenues within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $22 million decrease in depreciation and amortization for APCo primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia.

- Interest and Investment Income increased $15 million primarily due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- Carrying Costs Income increased $272 million primarily due to the following:
  - A $261 million increase in carrying costs income due to the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
  - A $10 million increase due to the recognition of equity carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which required the POLR refund to be applied against any deferred fuel balances. The equity carrying costs income was offset by amounts in Depreciation and Amortization discussed above.
- Allowance for Equity Funds Used During Construction increased $9 million primarily due to construction of the Turk and Dresden Plants and various environmental upgrades, partially offset by a decrease due to the completion of the Stall Unit in June 2010.

- Interest Expense decreased $28 million primarily due to lower outstanding debt balances.
- Equity Earnings of Unconsolidated Subsidiaries increased $12 million primarily due to an increase in transmission investments by ETT.
- Income Tax Expense increased $163 million primarily due to an increase in pretax book income, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

AEP RIVER OPERATIONS

Third Quarter of 2011 Compared to Third Quarter of 2010

Net Income from our AEP River Operations segment increased from $14 million in 2010 to $17 million in 2011. AEP River had increases in revenues related to higher coal exports and increased barge fleet size partially offset by increases in expenses related to higher fuel, maintenance and flood-related costs.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Net Income from our AEP River Operations segment increased from $16 million in 2010 to $23 million in 2011 primarily due to higher grain shipping rates, increased coal exports, increased barge fleet size and the cost reduction initiatives recorded in the second quarter of 2010, partially offset by higher fuel, maintenance and flood-related costs.

GENERATION AND MARKETING

Third Quarter of 2011 Compared to Third Quarter of 2010

Net Income from our Generation and Marketing segment increased from $0 in 2010 to $8 million in 2011 primarily due to increased inception gains from ERCOT marketing activities and increased gross margins at the Oklaunion Plant.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Net Income from our Generation and Marketing segment increased from $17 million in 2010 to $20 million in 2011 primarily due to increased inception gains from ERCOT marketing activities and increased income from our wind farm operations partially offset by lower gross margins at the Oklaunion Plant.

ALL OTHER

Third Quarter of 2011 Compared to Third Quarter of 2010

Net Income from All Other decreased from a gain of $2 million in 2010 to a loss of $10 million in 2011 primarily due to favorable federal income tax adjustments in the third quarter of 2010.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Net Income from All Other decreased from a loss of $10 million in 2010 to a loss of $54 million in 2011 due to a $22 million net-of-tax loss incurred in the first quarter of 2011 related to the settlement of litigation with BOA and Enron and a $10 million net-of-tax gain on the sale of our remaining 138,000 shares of ICE in the second quarter of 2010.

AEP SYSTEM INCOME TAXES

Third Quarter of 2011 Compared to Third Quarter of 2010

Income Tax Expense increased $76 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Income Tax Expense increased $256 million primarily due to an increase in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, offset in part by the 2010 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. Target debt to equity ratios are included in our credit arrangements as covenants that must be met for borrowing to continue.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2011		December 31, 2010	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 16,450	50.7 %	$ 16,811	52.8 %
Short-term Debt	1,279	3.9	1,346	4.2
Total Debt	17,729	54.6	18,157	57.0
Preferred Stock of Subsidiaries	60	0.2	60	0.2
AEP Common Equity	14,653	45.2	13,622	42.8
Total Debt and Equity Capitalization	$ 32,442	100.0 %	$ 31,839	100.0 %

Our ratio of debt-to-total capital decreased from 57% at December 31, 2010 to 54.6% at September 30, 2011. The decrease is due to increased equity, as a result of the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts written off in 2005, and reduced debt.

In October 2011, we announced our intent to redeem all of the outstanding preferred stock of our subsidiaries in December 2011.

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, 2011, we had $3.25 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization 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.

17

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At September 30, 2011, our available liquidity was approximately $3.2 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
	Revolving Credit Facility	$ 1,500	June 2015
	Revolving Credit Facility	1,750	July 2016
Total		3,250	
Cash and Cash Equivalents		546	
Total Liquidity Sources		3,796	
Less:	AEP Commercial Paper Outstanding	529	
	Letters of Credit Issued	103	
Net Available Liquidity		$ 3,164	

We have credit facilities totaling $3.25 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.35 billion. In July 2011, we replaced the $1.5 billion facility due in 2012 with a new $1.75 billion facility maturing in July 2016 and extended the $1.5 billion facility due in 2013 to expire in June 2015.

In March 2011, we terminated a $478 million credit facility, used for letters of credit to support variable rate debt, that was scheduled to mature in April 2011. In March 2011, we issued bilateral letters of credit to support the remarketing of $357 million of the variable rate debt and reacquired the remaining $115 million which are held by a trustee on our behalf.

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 the first nine months of 2011 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2011 was 0.38%.

Securitized Accounts Receivables

In July 2011, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million with the seasonal increase to $425 million for the months of July, August and September expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

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 capitalization 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, 2011, this contractually-defined percentage was 50.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. At September 30, 2011, 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, 2011, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.47 per share in October 2011. 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. AEP's income derives from our common stock equity in the earnings of our utility subsidiaries. Various 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 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

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but 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. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

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

	Nine Months Ended September 30,	
	2011	2010
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 294	$ 490
Net Cash Flows from Operating Activities	3,338	1,702
Net Cash Flows Used for Investing Activities	(1,967)	(1,575)
Net Cash Flows from (Used for) Financing Activities	(1,119)	473
Net Increase in Cash and Cash Equivalents	252	600
Cash and Cash Equivalents at End of Period	$ 546	$ 1,090

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, 2011		2010	
	(in millions)			
Net Income	$	1,638	$	1,040
Depreciation and Amortization		1,258		1,237
Other		442		(575)
Net Cash Flows from Operating Activities	$	3,338	$	1,702

Net Cash Flows from Operating Activities were $3.3 billion in 2011 consisting primarily of Net Income of $1.6 billion and $1.3 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. Following a Supreme Court of Texas opinion, we recorded an Extraordinary Item, Net of Tax of $273 million for the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005. We also recorded $261 million in Carrying Costs Income related to the TCC extraordinary item. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. We also contributed $150 million to our qualified pension trust.

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.

Investing Activities

	Nine Months Ended September 30, 2011	2010
	(in millions)	

Construction Expenditures	$	(1,849)	$	(1,629)
Acquisitions of Nuclear Fuel		(104)		(69)
Acquisition of Cushion Gas from BOA		(214)		-
Proceeds from Sales of Assets		116		160
Other		84		(37)
Net Cash Flows Used for Investing Activities	$	(1,967)	$	(1,575)

20

Net Cash Flows Used for Investing Activities were $2 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

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

Financing Activities

	Nine Months Ended September 30,			
	2011		2010	
	(in millions)			
Issuance of Common Stock, Net	$	70	$	65
Issuance (Retirement) of Debt, Net		(469)		1,087
Dividends Paid on Common Stock		(668)		(602)
Other		(52)		(77)
Net Cash Flows from (Used for) Financing Activities	$	(1,119)	$	473

Net Cash Flows Used for Financing Activities in 2011 were $1.1 billion. Our net debt retirements were $469 million. The net retirements included retirements of $683 million of senior unsecured and other debt notes, $678 million of pollution control bonds, $159 million of securitization bonds and a decrease in short-term borrowing of $67 million offset by issuances of $600 million of senior unsecured notes and $526 million of pollution control bonds. We paid common stock dividends of $668 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

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.

In October 2011, APCo remarketed $100 million of 2% Pollution Control Bonds due in 2014.

In October 2011, I&M retired $29 million of Notes Payable related to DCC Fuel.

OFF-BALANCE SHEET ARRANGEMENTS

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

	September 30, 2011		December 31, 2010	
	(in millions)			
Rockport Plant Unit 2 Future Minimum Lease Payments	$	1,700	$	1,774

Railcars Maximum Potential Loss From Lease Agreement	25	25

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" in the 2010 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2010 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section 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 Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection 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 Conner Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended September 30, 2011:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	2	-	1
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) *	-	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-
Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ Not assessed	$ -	$ Not assessed
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has three legal actions pending before the Federal Mine Safety and Health Review Commission. Two are related to actions challenging four violations issued by Mine Safety and Health Administration following an employee fatality in March 2009 and the third legal action is challenging a citation issued in August 2010 related to a dragline boom issue.

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” in the 2010 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

Pronouncements Effective in the Future

The FASB issued ASU 2011-05 “Presentation of Comprehensive Income” eliminating the option to present the components of other comprehensive income as a part of the statement of shareholders’ equity. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income. This standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2011. Early adoption is permitted. The FASB is currently considering deferral of reclassification adjustment presentation provisions of ASU 2011-05. Absent a deferral of this accounting guidance in its entirety, we expect to adopt ASU 2011-05 for the 2011 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial statements, contingencies, financial instruments, emission allowances, 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 MARKET RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and through its transactions 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 and, to a lesser extent, Ohio in PJM and MISO, 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 settle and expire in the fourth quarter of 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 power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President, 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, 2010:

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2011

	Utility Operations	Generation and Marketing	All Other	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets at December 31, 2010	$ 91	$ 140	$ 2	$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(23)	(17)	(2)	(42)
Fair Value of New Contracts at Inception When Entered During the Period (a)	3	14	-	17
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	5	4	-	9
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2	-	-	2
Total MTM Risk Management Contract Net Assets at September 30, 2011	$ 78	$ 141	$ -	219
Commodity Cash Flow Hedge Contracts				19
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(34)
Fair Value Hedge Contracts				-
Collateral Deposits				30
Total MTM Derivative Contract Net Assets at September 30, 2011				$ 234

(a) Reflects fair value on primarily 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) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the condensed 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, 2011, our credit exposure net of collateral to sub investment grade counterparties was approximately 5.5%, 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, 2011, 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%
	(in millions, except number of counterparties)				
Investment Grade	$ 534	$ 1	$ 533	1	$ 158
Split Rating	1	-	1	1	1
Noninvestment Grade	2	2	-	1	-
No External Ratings:					
Internal Investment Grade	192	-	192	1	76
Internal Noninvestment Grade	52	10	42	1	36
Total as of September 30, 2011	$ 781	$ 13	$ 768	5	$ 271
Total as of December 31, 2010	$ 946	$ 33	$ 913	7	$ 347

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, 2011, 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, 2011				Twelve Months Ended December 31, 2010			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 2	$ -	$ -	$ -	$ 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 movements 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 our 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 as of September 30, 2011 and December 31, 2010, the estimated EaR on our debt portfolio for the following twelve months was $23 million and $5 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2011 and 2010
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2011	2010	2011	2010
REVENUES				
Utility Operations	$ 4,044	$ 3,876	$ 10,901	$ 10,468
Other Revenues	289	188	771	525
TOTAL REVENUES	4,333	4,064	11,672	10,993
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,371	1,189	3,407	3,098
Purchased Electricity for Resale	294	247	856	712
Other Operation	747	707	2,130	2,374
Maintenance	283	262	864	776
Asset Impairments and Other Related Charges	90	-	90	-
Depreciation and Amortization	445	424	1,258	1,237
Taxes Other Than Income Taxes	213	210	628	619
TOTAL EXPENSES	3,443	3,039	9,233	8,816
OPERATING INCOME	890	1,025	2,439	2,177
Other Income (Expense):				
Interest and Investment Income	19	3	24	24
Carrying Costs Income	291	18	323	51
Allowance for Equity Funds Used During Construction	26	17	69	60
Interest Expense	(242)	(251)	(723)	(750)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	984	812	2,132	1,562
Income Tax Expense	334	258	786	530
Equity Earnings of Unconsolidated Subsidiaries	7	3	19	8
INCOME BEFORE EXTRAORDINARY ITEM	657	557	1,365	1,040
EXTRAORDINARY ITEM, NET OF TAX	273	-	273	-
NET INCOME	930	557	1,638	1,040

Less: Net Income Attributable to Noncontrolling Interests		1		1		3		3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS		929		556		1,635		1,037
Less: Preferred Stock Dividend Requirements of Subsidiaries		1		1		2		2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	928	$	555	$	1,633	$	1,035
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING		482,498,734		479,578,139		481,862,128		479,023,690
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS								
Income Before Extraordinary Item	$	1.35	$	1.16	$	2.82	$	2.16
Extraordinary Item, Net of Tax		0.57		-		0.57		-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	1.92	$	1.16	$	3.39	$	2.16
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING		482,796,945		479,750,447		482,126,964		479,261,415
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS								
Income Before Extraordinary Item	$	1.35	$	1.16	$	2.82	$	2.16
Extraordinary Item, Net of Tax		0.57		-		0.57		-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	1.92	$	1.16	$	3.39	$	2.16
CASH DIVIDENDS DECLARED PER SHARE	$	0.46	$	0.42	$	1.38	$	1.25

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, 2011 and 2010
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other Comprehensive Income (Loss)		
	Shares	Amount	Paid-in Capital	Retained Earnings		Noncontrolling Interests	Total
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
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622
Issuance of Common Stock	2	14	56				70

Common Stock Dividends				(665)		(3)	(668)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Other Changes in Equity			(8)				(8)
SUBTOTAL – EQUITY							13,014
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $8					(14)		(14)
Securities Available for Sale, Net of Tax of $2					(3)		(3)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $9					18		18
NET INCOME				1,635		3	1,638
TOTAL COMPREHENSIVE INCOME							1,639
TOTAL EQUITY – SEPTEMBER 30, 2011	503	$ 3,271	$ 5,952	$ 5,810	$ (380)	$ -	$ 14,653

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2011 and December 31, 2010
(in millions)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 546	$ 294
Other Temporary Investments		
(September 30, 2011 and December 31, 2010 amounts include $211 and $287, respectively, related to Transition Funding and EIS)	240	416
Accounts Receivable:		
Customers	622	683
Accrued Unbilled Revenues	139	195
Pledged Accounts Receivable - AEP Credit	1,024	949
Miscellaneous	109	137
Allowance for Uncollectible Accounts	(34)	(41)
Total Accounts Receivable	1,860	1,923
Fuel	544	837
Materials and Supplies	629	611
Risk Management Assets	164	232
Accrued Tax Benefits	78	389
Regulatory Asset for Under-Recovered Fuel Costs	78	81
Margin Deposits	62	88
Prepayments and Other Current Assets	173	145
TOTAL CURRENT ASSETS	4,374	5,016
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,666	24,352
Transmission	8,826	8,576
Distribution	14,620	14,208
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,880	3,846
Construction Work in Progress	3,105	2,758
Total Property, Plant and Equipment	55,097	53,740
Accumulated Depreciation and Amortization	18,680	18,066
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	36,417	35,674
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,731	4,943
Securitized Transition Assets	1,625	1,742
Spent Nuclear Fuel and Decommissioning Trusts	1,513	1,515
Goodwill	76	76
Long-term Risk Management Assets	316	410

Deferred Charges and Other Noncurrent Assets		1,135		1,079
TOTAL OTHER NONCURRENT ASSETS		10,396		9,765
TOTAL ASSETS	$	51,187	$	50,455

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, 2011 and December 31, 2010
(dollars in millions)
(Unaudited)

	2011	2010
CURRENT LIABILITIES		
Accounts Payable	$ 1,003	$ 1,061
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	750	690
Other Short-term Debt	529	656
Total Short-term Debt	1,279	1,346
Long-term Debt Due Within One Year		
(September 30, 2011 and December 31, 2010 amounts include $264 and $237, respectively, related to Transition Funding, DCC Fuel and Sabine)	1,267	1,309
Risk Management Liabilities	113	129
Customer Deposits	280	273
Accrued Taxes	501	702
Accrued Interest	235	281
Regulatory Liability for Over-Recovered Fuel Costs	2	17
Deferred Gain and Accrued Litigation Costs	-	448
Other Current Liabilities	1,004	952
TOTAL CURRENT LIABILITIES	5,684	6,518
NONCURRENT LIABILITIES		
Long-term Debt		
(September 30, 2011 and December 31, 2010 amounts include $1,625 and $1,857, respectively, related to Transition Funding, DCC Fuel and Sabine)	15,183	15,502
Long-term Risk Management Liabilities	133	141
Deferred Income Taxes	8,108	7,359
Regulatory Liabilities and Deferred Investment Tax Credits	3,229	3,171
Asset Retirement Obligations	1,441	1,394
Employee Benefits and Pension Obligations	1,718	1,893
Deferred Credits and Other Noncurrent Liabilities	978	795
TOTAL NONCURRENT LIABILITIES	30,790	30,255
TOTAL LIABILITIES	36,474	36,773
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	60
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
EQUITY		

Common Stock – Par Value – $6.50 Per Share:

	2011	2010				
Shares Authorized	600,000,000	600,000,000				
Shares Issued	503,177,402	501,114,881				
(20,307,725 shares were held in treasury at September 30, 2011 and December 31, 2010)				3,271		3,257
Paid-in Capital				5,952		5,904
Retained Earnings				5,810		4,842
Accumulated Other Comprehensive Income (Loss)				(380)		(381)
TOTAL AEP COMMON SHAREHOLDERS’ EQUITY				14,653		13,622
TOTAL EQUITY				14,653		13,622
TOTAL LIABILITIES AND EQUITY			$	51,187	$	50,455

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, 2011 and 2010
(in millions)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$ 1,638	$ 1,040
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,258	1,237
Deferred Income Taxes	764	404
Gain on Settlement with BOA and Enron	(51)	-
Settlement of Litigation with BOA and Enron	(211)	-
Extraordinary Item, Net of Tax	(273)	-
Asset Impairments and Other Related Charges	90	-
Carrying Costs Income	(323)	(51)
Allowance for Equity Funds Used During Construction	(69)	(60)
Mark-to-Market of Risk Management Contracts	84	(108)
Amortization of Nuclear Fuel	108	113
Pension Contributions to Qualified Plan Trust	(150)	(463)
Property Taxes	173	157
Fuel Over/Under-Recovery, Net	(94)	(233)
Change in Other Noncurrent Assets	(32)	(50)
Change in Other Noncurrent Liabilities	225	183
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	51	(766)
Fuel, Materials and Supplies	275	240
Margin Deposits	26	3
Accounts Payable	(66)	(163)
Accrued Taxes, Net	(42)	223
Accrued Interest	(46)	(32)
Other Current Assets	(13)	35
Other Current Liabilities	16	(7)
Net Cash Flows from Operating Activities	3,338	1,702
INVESTING ACTIVITIES		
Construction Expenditures	(1,849)	(1,629)
Change in Other Temporary Investments, Net	62	63
Purchases of Investment Securities	(1,024)	(1,542)
Sales of Investment Securities	1,094	1,477
Acquisitions of Nuclear Fuel	(104)	(69)
Acquisitions of Assets	(10)	(16)
Acquisition of Cushion Gas from BOA	(214)	-
Proceeds from Sales of Assets	116	160
Other Investing Activities	(38)	(19)
Net Cash Flows Used for Investing Activities	(1,967)	(1,575)

FINANCING ACTIVITIES				
Issuance of Common Stock, Net		70		65
Issuance of Long-term Debt		1,118		1,201
Commercial Paper and Credit Facility Borrowings		462		195
Change in Short-term Debt, Net		290		1,223
Retirement of Long-term Debt		(1,520)		(1,454)
Commercial Paper and Credit Facility Repayments		(819)		(78)
Principal Payments for Capital Lease Obligations		(53)		(74)
Dividends Paid on Common Stock		(668)		(602)
Dividends Paid on Cumulative Preferred Stock		(2)		(2)
Other Financing Activities		3		(1)
Net Cash Flows from (Used for) Financing Activities		(1,119)		473
Net Increase in Cash and Cash Equivalents		252		600
Cash and Cash Equivalents at Beginning of Period		294		490
Cash and Cash Equivalents at End of Period	$	546	$	1,090
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	716	$	755
Net Cash Paid (Received) for Income Taxes		(119)		(243)
Noncash Acquisitions Under Capital Leases		39		190
Government Grants Included in Accounts Receivable at September 30,		2		-
Construction Expenditures Included in Current Liabilities at September 30,		304		229
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement		27		-

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF 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, 2011 is not necessarily indicative of results that may be expected for the year ending December 31, 2011. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2010 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 25, 2011.

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, the power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

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 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, 2011 and 2010 were $33 million and $30 million, respectively, and for the nine months ended September 30, 2011 and 2010 were $97 million and $103 million, respectively. See the tables below for the classification of Sabine’s assets and liabilities on our condensed 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 expense to the protected cell for the three months ended September 30, 2011 and 2010 was $16 million and $15 million, respectively, and for the nine months ended September 30, 2011 and 2010 was $46 million and $33 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our condensed balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC (collectively DCC Fuel). DCC Fuel was 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. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and began in January 2011. Payments on the DCC Fuel leases for the three months ended September 30, 2011 and 2010 were $6 million and $0, respectively, and for the nine months ended September 30, 2011 and 2010 were $49 million and $22 million, respectively. 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, 54 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 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 a minimum of 5% equity and 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 securitized 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 balance sheets. See "Securitized Accounts Receivable – AEP Credit" section of Note 11.

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 $1.7 billion and $1.8 billion at September 30, 2011 and December 31, 2010, respectively, and are included in current and long-term debt on the condensed balance sheets. Transition Funding has securitized transition assets of $1.6 billion and $1.7 billion at September 30, 2011 and December 31 2010, respectively, which are presented separately on the face of the condensed 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. See the tables below for the classification of Transition Funding's assets and liabilities on our condensed balance sheets.

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, 2011
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 43	$ 93	$ 126	$ 1,013	$ 162
Net Property, Plant and Equipment	143	104	-	-	-
Other Noncurrent Assets	26	67	7	1	1,629
Total Assets	$ 212	$ 264	$ 133	$ 1,014	$ 1,791
LIABILITIES AND EQUITY					
Current Liabilities	$ 50	$ 75	$ 46	$ 962	$ 206
Noncurrent Liabilities	162	189	73	1	1,571
Equity	-	-	14	51	14
Total Liabilities and Equity	$ 212	$ 264	$ 133	$ 1,014	$ 1,791

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 50	$ 92	$ 131	$ 924	$ 214
Net Property, Plant and Equipment	139	173	-	-	-
Other Noncurrent Assets	34	112	1	10	1,746
Total Assets	$ 223	$ 377	$ 132	$ 934	$ 1,960
LIABILITIES AND EQUITY					
Current Liabilities	$ 33	$ 79	$ 33	$ 886	$ 221
Noncurrent Liabilities	190	298	85	1	1,725
Equity	-	-	14	47	14
Total Liabilities and Equity	$ 223	$ 377	$ 132	$ 934	$ 1,960

DHLC is a mining operator that 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 50% 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. SWEPCo's total billings from DHLC for the three months ended September 30, 2011 and 2010 were $18 million and $14 million, respectively, and for the nine months ended September 30, 2011 and 2010 were $47 million and $40 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on our condensed balance sheets.

Our investment in DHLC was:

	September 30, 2011		December 31, 2010	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 6	$ 6
Retained Earnings	1	1	2	2
SWEPCo's Guarantee of Debt	-	49	-	48
Total Investment in DHLC	$ 9	$ 58	$ 8	$ 56

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). In February 2011, PJM directed that work on the PATH project be suspended. PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. 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 balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. As of September 30, 2011, PATH-WV had 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, 2011		December 31, 2010	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 18	$ 18
Retained Earnings	9	9	6	6
Total Investment in PATH-WV	$ 28	$ 28	$ 24	$ 24

Earnings Per Share (EPS)

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

Amounts Attributable to AEP Common Shareholders	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)			
Income Before Extraordinary Item	$ 655	$ 555	$ 1,360	$ 1,035
Extraordinary Item, Net of Tax	273	-	273	-
Net Income	$ 928	$ 555	$ 1,633	$ 1,035

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 tables present our basic and diluted EPS calculations included on our condensed statements of income:

	Three Months Ended September 30,					
	2011			2010		
	(in millions, except per share data)					
			$/share			$/share
Earnings Attributable to AEP Common Shareholders	$ 928			$ 555		
Weighted Average Number of Basic Shares Outstanding	482.5	$	1.92	479.6	$	1.16
Weighted Average Dilutive Effect of:						
Stock Options	0.1		-	0.1		-
Restricted Stock Units	0.2		-	0.1		-
Weighted Average Number of Diluted Shares Outstanding	482.8	$	1.92	479.8	$	1.16

	Nine Months Ended September 30,					
	2011			2010		
	(in millions, except per share data)					
			$/share			$/share
Earnings Attributable to AEP Common Shareholders	$ 1,633			$ 1,035		
Weighted Average Number of Basic Shares Outstanding	481.9	$	3.39	479.0	$	2.16
Weighted Average Dilutive Effect of:						
Performance Share Units	-		-	0.1		-
Stock Options	-		-	0.1		-
Restricted Stock Units	0.2		-	0.1		-
Weighted Average Number of Diluted Shares Outstanding	482.1	$	3.39	479.3	$	2.16

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

Options to purchase 10,000 and 136,250 shares of common stock were outstanding at September 30, 2011 and 2010, 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.

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 Issued During 2011

The following standard was issued during the first nine months of 2011. The following paragraphs discuss its impact on future financial statements.

ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05)

In June 2011, the FASB issued ASU 2011-05 eliminating the option to present the components of other comprehensive income as a part of the statement of shareholders' equity. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2011. Early adoption is permitted. This standard must be retrospectively applied to all reporting periods presented in financial reports issued after the effective date. This standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. The FASB is currently considering deferral of reclassification adjustment presentation provisions of ASU 2011-05. Absent a deferral of this accounting guidance in its entirety, we expect to adopt ASU 2011-05 for the 2011 Annual Report.

EXTRAORDINARY ITEM

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts. In September 2011, the PUCT issued a preliminary order in a remand proceeding. Based upon the Supreme Court of Texas opinion, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Item, Net of Tax on the condensed statements of income in the third quarter of 2011. See "Texas Restructuring" section of Note 3.

3. RATE MATTERS

As discussed in the 2010 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2010 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 2011 and updates the 2010 Annual Report.

Regulatory Assets Not Yet Being Recovered

	September 30, 2011	December 31, 2010
	(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		
Capacity Auction True-Up - TCC	$ 682	$ -
Line Extension Carrying Costs - CSPCo, OPCo	64	55
Customer Choice Deferrals - CSPCo, OPCo	60	59
Storm Related Costs - CSPCo, OPCo	31	30
Storm Related Costs - TCC	25	25
Economic Development Rider - CSPCo, OPCo	12	6
Acquisition of Monongahela Power - CSPCo	9	8
Other Regulatory Assets Not Yet Being Recovered	1	1
Regulatory Assets Currently Not Earning a Return		
Environmental Rate Adjustment Clause - APCo	73	56
Deferred Wind Power Costs - APCo	40	29
Storm Related Costs - APCo, KGPCo	27	28
Mountaineer Carbon Capture and Storage Product Validation Facility - APCo	19	60
Special Rate Mechanism for Century Aluminum - APCo	13	13

Mountaineer Carbon Capture and Storage Commercial Scale Facility - APCo,				
I&M, KPCo, PSO, SWEPCo		12		-
Litigation Settlement - I&M		11		-
Acquisition of Monongahela Power - CSPCo		4		4
Storm Related Costs - PSO		-		17
Other Regulatory Assets Not Yet Being Recovered		6		4
Total Regulatory Assets Not Yet Being Recovered	$	1,089	$	395

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESPs

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 through 2011. The order also limited 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. In November 2009, the PUCO's order was appealed to the Supreme Court of Ohio (the Court). In April 2011, the Court issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. The order required CSPCo and OPCo to refund Provider of Last Resort (POLR) charges which were collected subject to refund since June 2011. According to the order, CSPCo and OPCo are required to apply the refund first to the FAC deferral with any remaining balance to be credited to CSPCo's and OPCo's customers in November and December 2011. As a result, in the third quarter of 2011, CSPCo and OPCo recorded pretax refund provisions of $34 million and $9 million, respectively, on the condensed statements of income. The PUCO order also agreed with CSPCo's and OPCo's position that the ESP statute provided a legal basis for reflecting an environmental carrying charge in CSPCo's and OPCo's base generation rates. In addition, the PUCO rejected the intervenors' proposed adjustments to the FAC deferral balance for POLR charges and environmental carrying charges for the period from April 2009 through May 2011. This decision is subject to rehearing and appeal.

In April 2010, the Industrial Energy Users-Ohio (IEU) filed an additional notice of appeal with the Court challenging alleged retroactive ratemaking, CSPCo 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. In June 2011, the Court affirmed the PUCO's decision and dismissed the IEU's appeal.

In January 2011, the PUCO issued an order on CSPCo's and OPCo's 2009 SEET filings and determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo earnings exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered CSPCo to refund $43 million of its pretax earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. The PUCO ordered that the significantly excessive earnings be applied first to CSPCo's FAC deferral, including unrecognized equity carrying costs, as of the date of the order, with any remaining balance to be credited to CSPCo's customers on a per kilowatt basis. That credit began with the first billing cycle in February 2011 and will continue through December 2011. Several parties, including CSPCo and OPCo, filed requests for rehearing with the PUCO, which were denied in March 2011. In May 2011, the IEU and the Ohio Energy Group filed appeals with the Court challenging the PUCO's SEET decisions.

In July 2011, CSPCo and OPCo filed their 2010 SEET filings with the PUCO. Based upon the approach in the PUCO 2009 order, management does not currently believe that CSPCo or OPCo will have any significantly excessive earnings. In October 2011, the Ohio Consumers' Counsel and the Ohio Energy Group filed testimony that recommended CSPCo refund up to $41 million of its 2010 earnings. Also in October 2011, the PUCO staff filed testimony that recommended CSPCo refund $21 million of its 2010 earnings.

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

39

January 2012 – May 2016 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing on a combined company basis for generation. The ESP also includes alternative energy resource requirements and addresses provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio, generation resources and other matters. The SSO presents redesigned generation rates by customer class. Customer class rates vary, but on average, customers will experience base generation increases of 1.4% in 2012 and 2.7% in 2013.

In September 2011, a stipulation agreement was filed with the PUCO by CSPCo, OPCo, the PUCO staff and multiple other parties which involved various issues pending before the PUCO, including the approval of the CSPCo/OPCo merger and the recovery of deferred fuel until securitized. The FAC deferral as of September 30, 2011 was $542 million for OPCo, excluding $40 million of unrecognized equity carrying costs. CSPCo did not have a FAC deferral as of September 30, 2011. Under the stipulation agreement, rates would be effective with the first billing cycle of January 2012 through the last billing cycle of May 2016. Prior to June 2015, CSPCo's and OPCo's SSO customers continue to pay the tariff rate for non-fuel generation and the fuel adjustment clause. Beginning in June 2015, CSPCo and OPCo will use results from a competitive bidding process performed prior to January 2015 to meet their SSO obligation through May 2016. The stipulation agreement proposed a corporate separation plan of CSPCo's and OPCo's generation assets to complete the transition to a fully competitive generation market by June 2015. In addition, to further develop customer choice and facilitate the transition to market generation pricing, CSPCo and OPCo will provide 21% of their generation capacity in 2012, 29% to 31% of their generation capacity in 2013 and 41% of their generation capacity beginning in 2014 through May 2015 to competitive retail suppliers at a charge based on the Reliability Pricing Model auction-clearing prices and the remainder at a discounted cost-based price.

The stipulation agreement also proposed a termination or modification of the Interconnection Agreement. See the "Possible Termination of the Interconnection Agreement" section of FERC rate matters. The current FAC mechanism would continue through May 2015. Finally, the stipulation agreement provides for certain CSPCo and OPCo contingent contributions and established a Distribution Investment Rider beginning January 2012 through May 2015 to recover post-2000 distribution investment with certain limitations.

Various intervenors who did not sign the stipulation agreement filed testimony that generally asserts CSPCo's and OPCo's proposed SSO rates are higher than the market-rate offer and that the proposed capacity charges to competitive retail suppliers are anti-competitive. Hearings on the stipulation agreement are ongoing. A decision from the PUCO is expected in the fourth quarter of 2011. If OPCo is not ultimately permitted to fully recover its FAC deferral, it would reduce future net income and cash flows and impact financial condition.

2011 Ohio Distribution Base Rate Case

In February 2011, CSPCo and OPCo filed with the PUCO for annual increases in distribution rates of $34 million and $60 million, respectively. The requested increase is based upon an 11.15% return on common equity to be effective January 2012.

In addition to the annual increases, CSPCo and OPCo requested recovery of the projected December 31, 2012 balances of certain distribution regulatory assets of $216 million and $159 million, respectively, including approximately $102 million and $84 million, respectively, of unrecognized equity carrying costs. These assets and unrecognized carrying costs would be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013. The actual balance of these distribution regulatory assets as of September 30, 2011 was $102 million and $66 million for CSPCo and OPCo, respectively, excluding $64 million and $48 million, respectively, of unrecognized equity carrying costs.

In September 2011, the PUCO staff filed testimony that recommended a rate reduction for CSPCo in the range of $2 million to $10 million and a rate increase for OPCo in the range of $23 million to $32 million based upon a return on common equity range of 8.58% to 9.6%. In addition, the PUCO staff recommended recovery of the deferred distribution regulatory assets subject to a review of the carrying costs. A decision from the PUCO is expected in the fourth quarter of 2011. If CSPCo and OPCo are not ultimately permitted to fully recover their deferrals, it would 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. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. In July 2011, the FERC issued an order approving the proposed merger. In September 2011, a stipulation agreement was filed with the PUCO which recommended CSPCo merge into OPCo by the end of 2011. A decision from the PUCO is expected in the fourth quarter of 2011. See “January 2012 – May 2016 ESP” section above.

Sporn Unit 5

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 2009 – 2011 ESP proceeding. In April 2011, intervenors filed comments opposing OPCo’s application. A PUCO decision is pending as to whether a hearing will be ordered.

In the third quarter of 2011, management decided to no longer offer Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the AEP Power Pool. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the condensed statements of income.

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 CSPCo and OPCo for the period of January 2009 through December 2009. In May 2010, the outside consultant provided its confidential audit report to the PUCO. The audit report included a recommendation that the PUCO 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 was recognized as a reduction to fuel expense in 2009 and 2010. Hearings were held in August 2010. A decision from the PUCO is pending. Management is unable to predict the outcome of this proceeding. If the PUCO orders any portion of the $58 million previously recognized gains or any future adjustments be used to reduce the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

2010 Fuel Adjustment Clause Audit

In May 2011, the PUCO-selected outside consultant issued its results of the 2010 FAC audit for CSPCo and OPCo. The audit report included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balances and determine whether the carrying costs on the balances should be net of accumulated income taxes. As of September 30, 2011, the amount of OPCo’s carrying costs that could potentially be at risk is estimated to be $12 million, excluding $14 million of unrecognized equity carrying costs. The amount of carrying costs for CSPCo that could potentially be at risk is immaterial. A decision from the PUCO is pending. Management is unable to predict the outcome of this proceeding. If the PUCO order results in a reduction in the carrying charges related to the FAC deferrals, 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 and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio's April 2011 decision referenced in the "2009-2011 ESPs" section above. The approval of the FAC as part of the ESP, 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. These amounts exclude $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 2009-2011 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 and this issue remains pending before the PUCO. 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 (IEU) 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 IEU 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 2011, the Supreme Court of Ohio affirmed the PUCO's decision and dismissed the IEU's appeal.

In June 2010, the IEU filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio raising the same issues as noted in the 2009 EDR appeal. In addition, the IEU added 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. In June 2011, the IEU voluntarily dismissed the 2010 EDR appeal issues that were the same issues dismissed by the Supreme Court of Ohio in their 2009 EDR appeal referenced above. In August 2011, the Supreme Court of Ohio affirmed the PUCO's decision on the remaining issues.

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, 2011, CSPCo and OPCo have collected $12 million and $12 million, respectively, in pre-construction costs authorized in a June 2006 PUCO order and incurred $11 million and $11 million, respectively, in pre-construction costs. As a result, CSPCo and OPCo established net regulatory liabilities of approximately $1 million and $1 million, respectively. 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, any pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. As of June 2011, there were no active IGCC projects at other AEP sites. In June 2011, CSPCo and OPCo filed a recommendation with the PUCO to refund to customers $2 million and $2 million, respectively, for the over-recovered pre-construction costs including interest. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

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 are required to refund pre-construction costs collected in excess of the over-recovered pre-construction costs, 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 $129 million for transmission, excluding AFUDC. SWEPCo’s share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $129 million for transmission, excluding AFUDC. As of September 30, 2011, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $1.3 billion of expenditures (including AFUDC and capitalized interest of $197 million and related transmission costs of $88 million). As of September 30, 2011, the joint owners and SWEPCo have contractual construction commitments of approximately $163 million (including related transmission costs of $13 million). SWEPCo’s share of the contractual construction commitments is $123 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, 2011, of approximately $101 million (including related transmission cancellation fees of $1 million). SWEPCo’s share of the contractual construction cancellation fees would be approximately $74 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 jurisdictional 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. 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 CO2 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 contending that the PUCT’s grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is 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. Management is unable to predict the timing of the outcome related to this proceeding.

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. The parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas. In December 2010, the Circuit Court affirmed the APCEC. In January 2011, the same parties filed a notice of appeal with the Arkansas Court of Appeals.

A wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In 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, and sought a preliminary injunction to halt construction and for a temporary restraining order. In July 2010, the Hempstead County Hunting Club (Hunting

Club) also 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. 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. In May 2011, the Arkansas Supreme Court determined that these claims must first be brought before the APSC and that the federal court does not have jurisdiction to hear the state law claims. In 2010, the motions for preliminary injunction were partially granted by the Federal District Court for the Western District of Arkansas. 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 portions of two transmission lines. SWEPCo appealed the issuance of the preliminary injunction to the U.S. Eighth Circuit Court of Appeals, and in July 2011, the Court of Appeals affirmed the preliminary injunction and remanded the case to the district court. Management is unable to predict the timing or the outcome related to this remand proceeding.

In August 2011, a joint stipulation of dismissal was approved by the Federal District Court for the Western District of Arkansas that resolved all pending matters between SWEPCo, the Hunting Club and several other parties. As a result, the Hunting Club's challenge to the U.S. Army Corps of Engineers permit in the Federal District Court for the Western District of Arkansas was dismissed and the Hunting Club's appeal of the air permit was withdrawn. Additional judicial and administrative proceedings were terminated. The Sierra Club and the Audubon Society challenges to the wetlands and air permits remain pending.

In October 2011, the Sierra Club, the National Audubon Society and Audubon Arkansas filed a complaint with the APSC requesting that construction of the Turk Plant be halted until SWEPCo or the Arkansas Electric Cooperative Corporation obtain either a CECPN, or SWEPCo obtains a CCN and performs an Environmental Impact Statement on associated gas facilities. Management believes the complaint is without merit and intends to vigorously defend against the complaint.

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 and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Texas Turk Plant Rate Plan

In August 2011, SWEPCo requested approval of a three step plan from the PUCT for including the Turk Plant investment in Texas retail rates. If approved, step one would recover financing costs on 40% of the June 2011 Texas jurisdictional share of the Turk Plant construction work in progress balance from April 2012 through October 2012. In step two, which would be implemented in November 2012, additional financing costs would be recovered on 100% of the June 2011 Texas jurisdictional share of the Turk Plant CWIP balance and would continue until the Turk Plant costs are included in base rates. Once the Turk Plant goes into service, which is expected in the fourth quarter of 2012, SWEPCo proposes that it also be allowed to defer Turk Plant related depreciation expense, operating and maintenance expense and additional financing costs incurred for future recovery. The final step would be to file a complete base rate case which will include all of the Turk Plant investment and associated operating expenses. Based upon the Turk Plant being placed into service in the fourth quarter of 2012, SWEPCo expects to file a complete base rate case in the first half of 2013.

TCC 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 Supreme Court of Texas. In July 2011, the Supreme Court of Texas granted review and issued its opinion. No parties filed for rehearing with the Supreme Court of Texas, and the case was remanded to the PUCT. The following issues were decided by the Supreme Court:

- The PUCT's 2006 order denying recovery of capacity auction true-up amounts was reversed. Based upon the Supreme Court of Texas' opinion, TCC recorded $421 million of pretax income ($273 million, net of tax) in Extraordinary Item, Net of Tax on the condensed statements of income in the third quarter of 2011. Further, in October 2011, the PUCT issued a preliminary order in the remand proceeding.

Also in the third quarter of 2011, TCC recorded $261 million in pretax Carrying Costs Income on the condensed statements of income related to the debt component of carrying costs for the period from January 2002 through September 2011. This carrying costs income represents previously unrecorded earnings associated with restructuring in Texas since 2002. The total regulatory asset related to the capacity auction true-up as of September 30, 2011 was $682 million. In October 2011, TCC filed with the PUCT requesting a final determination of the amount to be securitized. In its filing, TCC presented three alternative carrying cost calculations through March 2012, the anticipated securitization date, where the debt and equity component of carrying costs ranged from $396 million to $756 million, including $280 million to $444 million for the debt component of carrying costs. As of September 30, 2011, the corresponding range of the debt and equity component of carrying costs was $368 million to $692 million, including $261 million to $410 million for the debt component of carrying costs. The final amount of carrying costs will be determined by the PUCT and could vary from the calculations presented by TCC. TCC plans to recognize debt carrying costs income prior to securitization and equity carrying costs income will be recognized as collected over the life of the securitization. A PUCT hearing is scheduled for November 2011.

- The Supreme Court of Texas reversed the Texas Court of Appeal's decision and found that the PUCT could adjust the net book value for what it determined to be commercially unreasonable conduct. This portion of the decision is unfavorable, but was already reflected in our financial statements.

- The Supreme Court of Texas affirmed the PUCT's finding that the sales price should be used to value TCC's nuclear generation. This portion of the decision is favorable, but this issue will have no impact on TCC's rate recovery as this was already reflected in our financial statements.

- The Supreme Court of Texas reversed the Texas Court of Appeal's decision and found it was appropriate for the PUCT to take into account previously refunded excess mitigation credits to affiliate retail electricity providers. This portion of the decision upheld the PUCT's decision. However, resolution of related issues will be addressed on remand in the excess earnings proceeding. See the "TCC Excess Earnings" section below.

- The PUCT decisions allowing recovery of construction work in progress balances and specifying the interest rate on stranded costs were upheld. These decisions are already reflected in our financial statements and were not addressed in the remand proceeding.

If TCC is not ultimately permitted to fully recover its deferrals, it would reduce future net income and cash flows and 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 including associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such a 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 additional interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS's 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, the Texas Court of Appeals, at the request of the PUCT, remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. The issue was not appealed to the Supreme Court of Texas but it was addressed in connection with the remand of the true-up proceeding. See the "Texas Restructuring Appeals" section above. In August 2011, the Supreme Court of Texas issued a mandate to return this proceeding and other true-up proceedings to the PUCT. The PUCT established a proceeding to address this issue along with other true-up remanded issues. TCC is not accruing interest on the $103 million because management believes 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 $30 million higher for the period July 2008 through September 2011.

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, 2011. 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 Texas Retail Electric Providers 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. In the true-up proceeding, the PUCT adjusted stranded costs for TCC's payment of excess earnings under the PUCT order. However, the PUCT did not properly recognize TCC's payment of interest under the prior order, causing TCC to refund interest twice. The Supreme Court of Texas approved the PUCT treatment of these matters in the true-up case, noting that TCC could pursue its additional interest claim in further proceedings related to the excess earnings order. TCC intends to assert its claims in a remand of this order to the PUCT.

APCo and WPCo Rate Matters

2011 Virginia Biennial Base Rate Case

In March 2011, APCo filed a generation and distribution base rate request with the Virginia SCC to increase annual base rates by $126 million based upon an 11.65% return on common equity to be effective no later than February 2012. The return on common equity includes a requested 0.5% renewable portfolio standards incentive as allowed by law. APCo proposed to mitigate the requested base rate increase by $51 million by maintaining current depreciation rates until the next biennial filing. If approved, APCo's net base rate increase would be $75 million.

In August 2011, the Virginia Attorney General filed testimony recommending no increase in annual base rates based on a return on common equity of 11.03%. Also in August 2011, the Virginia SCC staff filed testimony recommending an increase in annual base rates of $31 million based on a return on common equity of 10.83%. Hearings were held in September 2011. A decision from the Virginia SCC is pending.

Rate Adjustment Clauses

In 2007, the Virginia law governing the regulation of electric utility service was amended to, among other items, provide for rate adjustment clauses (RACs) beginning in January 2009 for the timely and current recovery of costs of: (a) transmission services billed by an RTO, (b) demand side management and energy efficiency programs, (c) renewable energy programs, (d) environmental compliance projects and (e) new generation facilities, including major unit modifications. In accordance with Virginia law, APCo is deferring incremental environmental costs incurred after December 2008 and renewable energy costs incurred after December 2007 which are not being recovered in current revenues. As of September 30, 2011, APCo has deferred $73 million of environmental costs (excluding $17 million of unrecognized equity carrying costs) and $40 million of renewable energy costs.

In March 2011, APCo filed for approval of an environmental RAC, a renewable energy program RAC and a generation RAC simultaneous with the 2011 Virginia base rate filing. The environmental RAC is requesting recovery of environmental compliance costs incurred from January 2009 through December 2010 of $77 million to be collected over two years beginning in February 2012. The renewable energy program RAC is requesting the incremental portion of deferred wind power costs for the Camp Grove and Fowler Ridge projects of $6 million. APCo plans to seek recovery of non-incremental deferred wind power costs ($34 million as of September 30, 2011) in future rate proceedings. The generation RAC is requesting recovery of the Dresden Plant, currently under construction. With Virginia SCC approval, APCo purchased the Dresden Plant from AEGCo in August 2011 for $302 million.

In August 2011, the Virginia SCC staff filed testimony in the environmental RAC proceeding recommending recovery, based upon the methodology used, of $37 million to $42 million of environmental compliance costs. In October 2011, a hearing examiner issued a report recommending recovery of $65 million of environmental compliance costs. An order is pending from the Virginia SCC. Also in August 2011, a stipulation agreement was filed with the Virginia SCC related to the generation RAC. The stipulation agreement allows recovery of the Dresden Plant costs totaling up to $27 million annually, effective March 2012. A decision from the Virginia SCC is pending. In September 2011, the Virginia SCC staff filed testimony in the renewable energy program RAC recommending incremental costs of $1 million to $6 million depending on whether 2008 and 2009 costs are includable. Hearings were held in October 2011. If the Virginia SCC were to disallow a portion of APCo's deferred costs, it would reduce future net income and cash flows.

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. In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $51 million based upon a 10% return on common equity. The approved settlement agreement also resulted in a pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility in the first quarter of 2011. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and allowed APCo and WPCo to defer and amortize $15 million of previously expensed costs related to the 2010 cost reduction initiatives, each over a period of seven years.

Mountaineer Carbon Capture and Storage Project

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2

required the recording of an asset retirement obligation and an offsetting regulatory asset. In May 2011, the PVF ended operations and decommissioning of the facility began.

In APCo's and WPCo's May 2010 West Virginia base rate filing, APCo and WPCo requested rate base treatment of the PVF, including recovery of the related asset retirement obligation regulatory asset amortization and accretion. In March 2011, a WVPSC order denied the request for rate base treatment of the PVF largely due to its experimental operation. The base rate order provided that should APCo construct a commercial scale carbon capture and sequestration (CCS) facility, only the West Virginia portion of the PVF costs, based on load sharing among certain AEP operating companies, may be considered used and useful plant in service and included in future rate base. As a result, in the first quarter of 2011, APCo recorded a pretax write-off of $41 million in Other Operation expense on the condensed statements of operations. See "2010 West Virginia Base Rate Case" section above. As of September 30, 2011, APCo has recorded a noncurrent regulatory asset of $19 million related to the PVF. If APCo cannot recover its remaining PVF investment and related accretion expenses, it would reduce future net income and cash flows.

Carbon Capture and Sequestration Project with the Department of Energy (DOE) (Commercial Scale Project)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale CCS facility at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE agreed to fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. Management informed the DOE that it completed a Front-End Engineering and Design (FEED) study during the third quarter of 2011 and was postponing any further CCS project activities because of the uncertainty about the regulation of CO2. In June 2011, the FEED study costs were allocated among the AEP East companies, PSO and SWEPCo based on eligible plants that could potentially benefit from the carbon capture. Requests for recovery are in process in Indiana, Michigan and Virginia. In September 2011, a stipulation agreement was filed with the PUCO related to the ESP proceedings. The stipulation agreement withdrew a proposed rider to recover CSPCo's and OPCo's portion of the CCS facility costs. As a result, in September 2011, CSPCo and OPCo recorded pretax write-offs of $2 million and $7 million, respectively, in Other Operation expense on the condensed statements of income. A decision is pending from the PUCO. See the "Ohio Electric Security Plan Filings" section above. As of September 30, 2011, the project has incurred $34 million in total costs and has received $13 million of DOE eligible funding resulting in $21 million of net costs, of which $2 million and $7 million was written off by CSPCo and OPCo, respectively. The remaining net costs are recorded in Regulatory Assets on APCo's, I&M's, KPCo's, PSO's and SWEPCo's condensed balance sheets as follows:

Company		(in millions)
APCo	$	4
I&M		2
KPCo		1
PSO		1
SWEPCo		4
Total	$	12

If the costs of the CCS project cannot be recovered, it would reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

In 2008, the Virginia SCC issued an order denying APCo's request for 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 order was based upon the Virginia SCC's 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 CCS facilities. During 2009, based on the order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional Certificate of Environmental Compatibility and Public Need granted in 2008 must be reconsidered if and when APCo proceeds with the IGCC plant.

Through September 30, 2011, 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 West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's 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.

In June 2010, the WVPSC approved a settlement agreement for $96 million, including $10 million of construction surcharges related to APCo's and WPCo's second year ENEC increase. The settlement agreement allows APCo to accrue a weighted average cost of a capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. The new rates became effective in July 2010.

In June 2011, the WVPSC issued an order approving a $98 million annual increase including $8 million of construction surcharges and $8 million of carrying charges related to APCo's and WPCo's third year ENEC increase. The order also allows APCo to accrue a fixed annual carrying cost rate of 4%. The new rates became effective in July 2011. Additionally, the order approved APCo's request to purchase the Dresden Plant, currently under construction, from AEGCo and approved deferral of post in-service Dresden Plant costs, including a return, for future recovery. APCo purchased the Dresden Plant at cost from AEGCo in August 2011 for $302 million. As of September 30, 2011, APCo's ENEC under-recovery balance was $380 million, excluding $8 million of unrecognized equity carrying costs, which is included in noncurrent regulatory assets. If the WVPSC were to disallow a portion of APCo's and WPCo's deferred ENEC costs, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

PSO 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 prudency review of the related costs. In March 2010, the Oklahoma Attorney General and the Oklahoma Industrial Energy Consumers (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 fuel transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of those ERCOT trading contracts. Hearings were held in June 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

Michigan 2009 and 2010 Power Supply Cost Recovery (PSCR) Reconciliations (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 Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized accidental outage insurance proceeds. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation. In March 2011, I&M filed its 2010 PSCR reconciliation with the MPSC. 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.

2011 Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense.

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense.

FERC Rate Matters

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.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding 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 asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and required 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. In September 2011, the FERC issued orders that denied all parties' request for rehearing of the initial decision.

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 $10 million including estimated interest of $3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. 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 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.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. No filings have been made at the FERC. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently.

In addition, in September 2011, a stipulation agreement was filed in the Ohio ESP proceeding which proposed to dissolve and/or modify the Interconnection Agreement. A decision from the PUCO regarding the stipulation agreement is expected in the fourth quarter of 2011. See "January 2012 - May 2016 ESP" section of the CSPCo and OPCo rate matters.

If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce 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 dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. In June 2011, the FERC approved the settlement agreement.

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 effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2010 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. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have credit facilities totaling $3.25 billion, under which we may issue up to $1.35 billion as letters of credit. In July 2011, we replaced the $1.5 billion facility due in 2012 with a new $1.75 billion facility maturing in July 2016 and extended the $1.5 billion facility due in 2013 to expire in June 2015. As of September 30, 2011, the maximum future payments for letters of credit issued under the two credit facilities were $103 million with maturities ranging from November 2011 to April 2012.

In March 2011, we terminated a $478 million credit agreement that was scheduled to mature in April 2011 and was used to support $472 million of variable rate Pollution Control Bonds. In March 2011, we remarketed $357 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $361 million. The remaining $115 million of Pollution Control Bonds were reacquired and are held by trustees.

In July 2011, we remarketed $45 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $46 million. Both letters of credit mature in July 2014.

51

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation. In July 2011, SWEPCo's guarantee was increased from $65 million to $100 million due to expansion of the mining area. 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, 2011, SWEPCo has collected approximately $52 million through a rider for final mine closure and reclamation costs, of which $1 million is recorded in Other Current Liabilities, $38 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $13 million is recorded in Asset Retirement Obligations on our condensed 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 2010 Annual Report "Dispositions" section of Note 7. As of September 30, 2011, there were no material liabilities recorded for any indemnifications.

Master Lease Agreements

We lease certain equipment under master lease agreements. In December 2010, we signed a new master lease agreement with GE Capital Commercial Inc. (GE) for approximately $137 million to replace existing operating and capital leases with GE. We refinanced $60 million of capital leases and $77 million of operating leases. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. In January 2011, we purchased $5 million of previously leased assets that were not included in the 2010 refinancing. In June 2011, we placed an additional $11 million of previously leased assets under a new capital lease.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% 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 78% of the unamortized balance. For equipment under other 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, 2011, the maximum potential loss for these lease agreements was approximately $16 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.

52

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 assignments are 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 $16 million for I&M and $18 million for SWEPCo for the remaining railcars as of September 30, 2011.

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 and SWEPCo’s is approximately $13 million 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.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants’ power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The 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. In 2010, the U.S. Supreme Court granted the defendants’ petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs’ federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA. After the remand, the plaintiffs asked the Second Circuit to return the case to the district court so that they could withdraw their complaints. The cases have been returned to the district court and the parties have been ordered to advise the court in November 2011 how they intend to proceed.

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. 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. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011 and set a status conference for December 1, 2011. We believe the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. We intend to vigorously defend against the claims. 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 CO_2 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. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court entered an order deferring argument until after June 2011 and the parties requested supplemental briefing on the impact of the Supreme Court's decision. The court has set a November 2011 date 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. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's provision is approximately \$11 million. 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 PM emission limits) that lasted for more than 30 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. In March 2011, we resolved these issues through the entry of a consent order that included the payment of a \$75 thousand civil penalty and certain improvements in our opacity reports.

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.

54

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 $408 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. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. As of September 30, 2011, we recorded $61 million in Prepayments and Other Current Assets on our condensed balance sheets representing amounts under NEIL insurance policies. Through September 30, 2011, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

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. The treatment of property damage 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 and reached an agreement (subject to IURC approval) in 2010. The agreement requires I&M to purchase the remaining leased property and settles claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, including interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. In August 2011, the IURC approved a settlement agreement with the Indiana Office of Utility Consumer Counselor. The transaction is final.

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 was litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

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. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed these awards and posted bonds covering the amounts. 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 decision as to the judgment dismissing our claims against BOA in the Southern District of Texas.

In 2005, we sold our interest in HPL for approximately $1 billion. Although the assets were legally transferred, we were unable to determine all costs associated with the transfer until the BOA litigation was resolved. We indemnified the buyer of HPL against any damages up to the purchase price resulting from the BOA litigation, including the right to use the 55 BCF of natural gas through 2031. As a result, we deferred the entire gain related to the sale of HPL (approximately $380 million) pending resolution of the Enron and BOA disputes.

The deferred gain related to the sale of HPL, plus accrued interest and attorneys' fees related to the New York court's judgment was $448 million at December 31, 2010 and was included in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the condensed balance sheet.

In February 2011, we reached a settlement covering all claims with BOA and Enron for $425 million. As part of the settlement, we received title to the 55 BCF of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

At the time of the settlement, the following table sets forth its impact on our 2011 financial statements:

		(in millions)
Income Statement:		
Other Operation Expense - Pretax Gain on Settlement	$	51
Income Tax Expense		73
Net Loss After Tax	$	(22)
Cash Flow Statement:		
Net Income - Loss on Settlement with BOA and Enron	$	(22)
Deferred Income Taxes		91
Gain on Settlement with BOA and Enron		(51)
Settlement of Litigation with BOA and Enron		(211)
Accrued Taxes, Net		(18)
Acquisition of Cushion Gas from BOA		(214)
Cash Paid	$	(425)
Balance Sheet:		

Deferred Charges and Other Noncurrent Assets - Gas Acquired	$ 214
Deferred Credits and Other Noncurrent Liabilities - Gas Service Liability	187
Accrued Taxes - Tax Benefit on Settlement with BOA and Enron	18
Deferred Income Taxes - Deferred Tax Benefit on Gas Service Liability	66

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. In 2008, we settled all of the cases pending against us in California. In July 2011, the judge in the Federal District Court in Las Vegas granted summary judgment dismissing the cases where AEP companies were defendants. Also in July 2011, the plaintiffs in these cases filed notices of appeal to the Ninth Circuit Court of Appeals. We will continue to defend the remaining case in Ohio where an AEP company is a defendant and all appeals of the cases that were dismissed by the Federal District Court in Las Vegas. We believe the provision we have for the remaining cases is adequate. We believe the remaining exposure is immaterial.

5. ACQUISITION, DISPOSITIONS AND IMPAIRMENTS

ACQUISITION

2010

Valley Electric Membership Corporation (Utility Operations segment)

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO’s 30,000 customers in Louisiana.

DISPOSITIONS

2010

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

During the nine months ended September 30, 2010, TCC and TNC sold, at cost, $66 million and $73 million, respectively, of transmission facilities to ETT.

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

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain. We recorded the gain in Interest and Investment Income on our condensed statements of income for the nine months ended September 30, 2010.

IMPAIRMENTS

2011

Muskingum River Plant Unit 5 FGD Project (MR5) (Utility Operations segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, management determined that OPCo was not likely to complete the previously suspended MR5 project and that the project’s preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the condensed statements of income.

Sporn Plant Unit 5 (Utility Operations segment)

In the third quarter of 2011, management decided to no longer offer Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the AEP Power Pool. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the condensed statements of income.

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, 2011 and 2010:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Service Cost	$ 18	$ 28	$ 11	$ 12
Interest Cost	59	63	27	29
Expected Return on Plan Assets	(79)	(78)	(27)	(27)
Amortization of Transition Obligation	-	-	1	6
Amortization of Prior Service Cost (Credit)	1	-	(1)	-
Amortization of Net Actuarial Loss	31	22	8	8
Net Periodic Benefit Cost	$ 30	$ 35	$ 19	$ 28

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Service Cost	$ 54	$ 83	$ 32	$ 35
Interest Cost	178	190	81	85
Expected Return on Plan Assets	(236)	(234)	(81)	(79)
Amortization of Transition Obligation	-	-	1	20
Amortization of Prior Service Cost (Credit)	1	-	(1)	-
Amortization of Net Actuarial Loss	92	67	23	22
Net Periodic Benefit Cost	$ 89	$ 106	$ 55	$ 83

7. BUSINESS SEGMENTS

As outlined in our 2010 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 and, to a lesser extent, Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

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

AEP River Operations
- Commercial barging operations that 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 and, to a lesser extent, Ohio in PJM and MISO.

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 expire in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ends in the fourth quarter of 2011.

The tables below present our reportable segment information for the three and nine months ended September 30, 2011 and 2010 and balance sheet information as of September 30, 2011 and December 31, 2010. 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, 2011						
Revenues from:						
External Customers	$ 4,044	$ 177	$ 106	$ 6	$ -	$ 4,333
Other Operating Segments	30	6	-	4	(40)	-
Total Revenues	$ 4,074	$ 183	$ 106	$ 10	$ (40)	$ 4,333
Income (Loss) Before Extraordinary Item	$ 642	$ 17	$ 8	$ (10)	$ -	$ 657
Extraordinary Item, Net of Tax	273	-	-	-	-	273
Net Income (Loss)	$ 915	$ 17	$ 8	$ (10)	$ -	$ 930

		Nonutility Operations			
	Utility	AEP River	Generation and	All Other	Reconciling

	Operations	Operations	Marketing	(a)	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

59

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Nine Months Ended September 30, 2011						
Revenues from:						
External Customers	$ 10,901	$ 506	$ 247	$ 18	$ -	$ 11,672
Other Operating Segments	86	15	1	7	(109)	-
Total Revenues	$ 10,987	$ 521	$ 248	$ 25	$ (109)	$ 11,672
Income (Loss) Before Extraordinary Item	$ 1,376	$ 23	$ 20	$ (54)	$ -	$ 1,365
Extraordinary Item, Net of Tax	273	-	-	-	-	273
Net Income (Loss)	$ 1,649	$ 23	$ 20	$ (54)	$ -	$ 1,638

		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

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
September 30, 2011						
Total Property, Plant and Equipment	$ 54,151	$ 600	$ 593	$ 11	$ (258)	$ 55,097
Accumulated Depreciation and Amortization	18,380	130	215	10	(55)	18,680
Total Property, Plant and Equipment - Net	$ 35,771	$ 470	$ 378	$ 1	$ (203)	$ 36,417
Total Assets	$ 49,651	$ 647	$ 883	$ 16,288	$ (16,282)(c)	$ 51,187

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
December 31, 2010						
Total Property, Plant and Equipment	$ 52,822	$ 574	$ 584	$ 11	$ (251)	$ 53,740
Accumulated Depreciation and Amortization	17,795	110	198	9	(46)	18,066
Total Property, Plant and Equipment - Net	$ 35,027	$ 464	$ 386	$ 2	$ (205)	$ 35,674
Total Assets	$ 48,780	$ 621	$ 881	$ 15,942	$ (15,769) (c)	$ 50,455

(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 expire in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ends in the fourth quarter of 2011.

(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.

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 our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of September 30, 2011 and December 31, 2010:

Notional Volume of Derivative Instruments

	Volume		
	September 30, 2011	December 31, 2010	Unit of Measure
	(in millions)		
Commodity:			
Power	730	652	MWHs
Coal	35	63	Tons
Natural Gas	92	94	MMBtus

Heating Oil and Gasoline		7		6	Gallons
Interest Rate	$	232	$	171	USD
Interest Rate and Foreign Currency	$	614	$	907	USD

61

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. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.” We do not hedge all fuel price risk.

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 on the condensed balance sheets 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.

62

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, 2011 and December 31, 2010 balance sheets, we netted $15 million and $8 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $45 million and $109 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 balance sheets as of September 30, 2011 and December 31, 2010:

Fair Value of Derivative Instruments
September 30, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in millions)		
Current Risk Management Assets	$ 557	$ 20	$ -	$ (413)	$ 164
Long-term Risk Management Assets	460	16	-	(160)	316
Total Assets	1,017	36	-	(573)	480
Current Risk Management Liabilities	528	12	17	(444)	113
Long-term Risk Management Liabilities	304	5	17	(193)	133
Total Liabilities	832	17	34	(637)	246
Total MTM Derivative Contract Net Assets (Liabilities)	$ 185	$ 19	$ (34)	$ 64	$ 234

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total

					(in millions)					
Current Risk Management Assets	$	1,023	$	18	$	30	$	(839)	$	232
Long-term Risk Management Assets		546		12		2		(150)		410
Total Assets		1,569		30		32		(989)		642
Current Risk Management Liabilities		995		13		2		(881)		129
Long-term Risk Management Liabilities		387		6		3		(255)		141
Total Liabilities		1,382		19		5		(1,136)		270
Total MTM Derivative Contract Net Assets (Liabilities)	$	187	$	11	$	27	$	147	$	372

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

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.

The tables below present our activity of derivative risk management contracts for the three and nine months ended September 30, 2011 and 2010:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2011 and 2010

Location of Gain (Loss)	2011	2010
	(in millions)	
Utility Operations Revenue	$ 8	$ 24
Other Revenue	6	(4)
Regulatory Assets (a)	(3)	(6)
Regulatory Liabilities (a)	(2)	7
Total Gain (Loss) on Risk Management Contracts	$ 9	$ 21

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2011 and 2010

Location of Gain (Loss)	2011	2010
	(in millions)	
Utility Operations Revenue	$ 46	$ 69
Other Revenue	21	5
Regulatory Assets (a)	(3)	(9)
Regulatory Liabilities (a)	8	34
Total Gain (Loss) on Risk Management Contracts	$ 72	$ 99

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

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 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 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 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."

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 statements of income. During the three and nine months ended September 30, 2011, we recognized gains of $1 million and $3 million, respectively, on our hedging instruments and offsetting losses of $3 million and $6 million, respectively, on our long-term debt. We de-designated a significant portion of our interest rate fair value hedges in the third quarter of 2011. Hedge ineffectiveness was immaterial. During the three and nine months ended September 30, 2010, we recognized gains of $3 million and $7 million, respectively, on our outstanding hedging instruments and offsetting losses of $3 million and $7 million, respectively, on our long-term debt. No hedge ineffectiveness was recognized.

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 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 statements of income, or in Regulatory Assets or Regulatory Liabilities on our condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2011 and 2010, 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 balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our condensed statements of income. During the three and nine months ended September 30, 2011 and 2010, 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, 2011 and 2010, 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 balance sheets into Depreciation and Amortization expense on our condensed 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, 2011 and 2010, we designated foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2011 and 2010, 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 Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2011 and 2010. All amounts in the following tables 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, 2011

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of June 30, 2011	$ 12	$ 5	$ 17
Changes in Fair Value Recognized in AOCI	2	(21)	(19)
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	(2)	-	(2)
Interest Expense	-	1	1
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2011	$ 12	$ (15)	$ (3)

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 Nine Months Ended September 30, 2011

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	7	(22)	(15)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Utility Operations Revenue	3	-	3
Other Revenue	(3)	-	(3)
Purchased Electricity for Resale	(3)	-	(3)
Interest Expense	-	3	3
Regulatory Assets (a)	1	-	1
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2011	$ 12	$ (15)	$ (3)

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 (in millions)	Total
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)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets at September 30, 2011 and December 31, 2010 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2011

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 23	$ -	$ 23
Hedging Liabilities (a)	4	34	38
AOCI Gain (Loss) Net of Tax	12	(15)	(3)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	5	(2)	3

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 13	$ 25	$ 38
Hedging Liabilities (a)	2	4	6
AOCI Gain (Loss) Net of Tax	7	4	11
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(2)	1

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed 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, 2011, 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 33 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 the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, we are obligated to post an additional 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: (a) our aggregate fair value of such derivative contracts, (b) 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 (c) how much was attributable to RTO and ISO activities as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 31	$ 20
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	59	45
Amount Attributable to RTO and ISO Activities	55	44

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 by Parent or the obligor under outstanding debt or a third party obligation 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: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) 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, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 339	$ 401
Amount of Cash Collateral Posted	21	81
Additional Settlement Liability if Cross Default Provision is Triggered	202	213

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. 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.

Assets in the nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. 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 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	
		X	X

Ratings Agency Updates		
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, 2011 and December 31, 2010 are summarized in the following table:

	September 30, 2011		December 31, 2010	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 16,450	$ 19,003	$ 16,811	$ 18,285

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, 2011			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 164	$ -	$ -	$ 164
Fixed Income Securities:				
Mutual Funds	63	-	-	63
Equity Securities - Mutual Funds	11	2	-	13
Total Other Temporary Investments	$ 238	$ 2	$ -	$ 240

	December 31, 2010			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 225	$ -	$ -	$ 225
Fixed Income Securities:				
Mutual Funds	69	-	-	69
Variable Rate Demand Notes	97	-	-	97
Equity Securities - Mutual Funds	18	7	-	25
Total Other Temporary Investments	$ 409	$ 7	$ -	$ 416

(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, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Proceeds from Investment Sales	$ 21	$ 133	$ 268	$ 390
Purchases of Investments	-	192	153	413
	4	-	4	16

Gross Realized Gains on Investment Sales				
Gross Realized Losses on Investment Sales	-	-	-	-

At September 30, 2011 and December 31, 2010, we had no Other Temporary Investments with an unrealized loss position. At September 30, 2011, fixed income securities are primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

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.

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. 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. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in the 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. Consequently, changes in fair value of trust assets do 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, 2011 and December 31, 2010:

	September 30, 2011			December 31, 2010		
	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	$ 14	$ -	$ -	$ 20	$ -	$ -
Fixed Income Securities:						
United States Government	550	59	(1)	461	23	(1)
Corporate Debt	53	5	(2)	59	4	(2)
State and Local Government	320	-	(1)	341	(1)	-
Subtotal Fixed Income Securities	923	64	(4)	861	26	(3)
Equity Securities - Domestic	576	144	(84)	634	183	(123)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,513	$ 208	$ (88)	$ 1,515	$ 209	$ (126)

72

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)			
Proceeds from Investment Sales	$ 361	$ 495	$ 826	$ 1,087
Purchases of Investments	379	512	871	1,129
Gross Realized Gains on Investment Sales	18	1	30	7
Gross Realized Losses on Investment Sales	12	-	21	-

The adjusted cost of debt securities was $859 million and $835 million as of September 30, 2011 and December 31, 2010, respectively. The adjusted cost of equity securities was $432 million and $451 million as of September 30, 2011 and December 31, 2010, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at September 30, 2011 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 79
1 year – 5 years	269
5 years – 10 years	318
After 10 years	257
Total	$ 923

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, 2011 and December 31, 2010. 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 our valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 13	$ -	$ -	$ 533	$ 546
Other Temporary Investments					
Restricted Cash (a)	123	-	-	41	164
Fixed Income Securities:					
Mutual Funds	63	-	-	-	63
Equity Securities - Mutual Funds (b)	13	-	-	-	13
Total Other Temporary Investments	199	-	-	41	240
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	25	855	105	(562)	423
Cash Flow Hedges:					
Commodity Hedges (c)	11	24	-	(12)	23
De-designated Risk Management Contracts (d)	-	-	-	34	34
Total Risk Management Assets	36	879	105	(540)	480
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	5	-	9	14
Fixed Income Securities:					
United States Government	-	550	-	-	550
Corporate Debt	-	53	-	-	53
State and Local Government	-	320	-	-	320
Subtotal Fixed Income Securities	-	923	-	-	923
Equity Securities - Domestic (b)	576	-	-	-	576
Total Spent Nuclear Fuel and Decommissioning Trusts	576	928	-	9	1,513
Total Assets	$ 824	$ 1,807	$ 105	$ 43	$ 2,779
Liabilities:					
Risk Management Liabilities					

Risk Management Commodity Contracts (c) (f)	$	25	$	734	$	41	$	(592)	$	208
Cash Flow Hedges:										
Commodity Hedges (c)		1		15		-		(12)		4
Interest Rate/Foreign Currency Hedges		-		34		-		-		34
Total Risk Management Liabilities	$	26	$	783	$	41	$	(604)	$	246

74

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Cash and Cash Equivalents (a)	$ 170	$ -	$ -	$ 124	$ 294
Other Temporary Investments					
Restricted Cash (a)	184	-	-	41	225
Fixed Income Securities:					
Mutual Funds	69	-	-	-	69
Variable Rate Demand Notes	-	97	-	-	97
Equity Securities - Mutual Funds (b)	25	-	-	-	25
Total Other Temporary Investments	278	97	-	41	416
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	20	1,432	112	(1,013)	551
Cash Flow Hedges:					
Commodity Hedges (c)	11	17	-	(15)	13
Interest Rate/Foreign Currency Hedges	-	25	-	-	25
Fair Value Hedges	-	7	-	-	7
De-designated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	31	1,481	112	(982)	642
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	8	-	12	20
Fixed Income Securities:					
United States Government	-	461	-	-	461
Corporate Debt	-	59	-	-	59
State and Local Government	-	341	-	-	341
Subtotal Fixed Income Securities	-	861	-	-	861
Equity Securities - Domestic (b)	634	-	-	-	634
Total Spent Nuclear Fuel and Decommissioning Trusts	634	869	-	12	1,515
Total Assets	$ 1,113	$ 2,447	$ 112	$ (805)	$ 2,867
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 25	$ 1,325	$ 27	$ (1,114)	$ 263
Cash Flow Hedges:					
Commodity Hedges (c)	4	13	-	(15)	2

Interest Rate/Foreign Currency Hedges		-		4		-		-		4
Fair Value Hedges		-		1		-		-		1
Total Risk Management Liabilities	$	29	$	1,343	$	27	$	(1,129)	$	270

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(f) The September 30, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $0 in 2011, $6 million in periods 2012-2014 and ($6) million in periods 2015-2016; Level 2 matures $3 million in 2011, $80 million in periods 2012-2014, $22 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $5 million in 2011, $17 million in periods 2012-2014, $13 million in periods 2015-2016 and $29 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.

(g) The December 31, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($2) million in 2011, $2 million in periods 2012-2014 and ($5) million in periods 2015-2018; Level 2 matures $13 million in 2011, $66 million in periods 2012-2014, $12 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $18 million in 2011, $24 million in periods 2012-2014, $16 million in periods 2015-2016 and $27 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended September 30, 2011	Net Risk Management Assets (Liabilities) (in millions)	
Balance as of June 30, 2011	$	77
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(16)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)		
Relating to Assets Still Held at the Reporting Date (a)		(5)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		3
Transfers into Level 3 (d) (f)		5
Transfers out of Level 3 (e) (f)		(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1
Balance as of September 30, 2011	$	64

Three Months Ended September 30, 2010	Net Risk Management Assets (Liabilities) (in millions)	
Balance as of June 30, 2010	$	100
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)		
Relating to Assets Still Held at the Reporting Date (a)		23
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		-
Transfers into Level 3 (d) (f)		5
Transfers out of Level 3 (e) (f)		(22)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		9
Balance as of September 30, 2010	$	111

Nine Months Ended September 30, 2011	Net Risk Management Assets (Liabilities)

		(in millions)
Balance as of December 31, 2010	$	85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(11)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		5
Transfers into Level 3 (d) (f)		9
Transfers out of Level 3 (e) (f)		(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		(12)
Balance as of September 30, 2011	$	64

Nine Months Ended September 30, 2010		Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2009	$	62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		4
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)		
Relating to Assets Still Held at the Reporting Date (a)		60
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(18)
Transfers into Level 3 (d) (f)		14
Transfers out of Level 3 (e) (f)		(26)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		15
Balance as of September 30, 2010	$	111

(a) Included in revenues on our condensed statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on our condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

10. INCOME TAXES

We, along with our subsidiaries, file a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

We are no longer subject to U.S. federal examination for years before 2009. We completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements will not have a material impact on net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material effect on net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

For a discussion of the tax implications of our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 4.

77

Federal Tax Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the nine months ended September 30, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on net income or financial condition.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rates from 8.5% to 6.5%. The current 8.5% Indiana corporate income tax rate is scheduled for a 0.5% reduction each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015. In addition, Michigan repealed its Business Tax regime in May 2011 and replaced it with a traditional corporate net income tax with a rate of 6%. During the third quarter of 2011, the state of West Virginia determined that the state had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced to 7.75% in 2012. The enacted provisions will not have a material impact on net income, cash flows or financial condition.

11. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	September 30, 2011		December 31, 2010	
	(in millions)			
Senior Unsecured Notes	$	11,737	$	11,669
Pollution Control Bonds		2,112		2,263
Notes Payable		337		396
Securitization Bonds		1,688		1,847
Junior Subordinated Debentures		315		315
Spent Nuclear Fuel Obligation (a)		265		265
Other Long-term Debt		28		91
Unamortized Discount (net)		(32)		(35)
Total Long-term Debt Outstanding		16,450		16,811
		1,267		1,309

Less Portion Due Within One Year				
Long-term Portion	$	15,183	$	15,502

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $308 million and $307 million at September 30, 2011 and December 31, 2010, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on our condensed balance sheets.

78

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2011 are shown in the tables below:

Company	Type of Debt		Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:					
APCo	Senior Unsecured Notes	$	350	4.60	2021
APCo	Pollution Control Bonds		65	2.00	2012
APCo	Pollution Control Bonds		75 (a)	Variable	2036
APCo	Pollution Control Bonds		54 (a)	Variable	2042
APCo	Pollution Control Bonds		50 (a)	Variable	2036
APCo	Pollution Control Bonds		50 (a)	Variable	2042
I&M	Pollution Control Bonds		52 (a)	Variable	2021
I&M	Pollution Control Bonds		25 (a)	Variable	2019
OPCo	Pollution Control Bonds		50 (a)	Variable	2014
PSO	Senior Unsecured Notes		250	4.40	2021
PSO	Notes Payable		2	3.00	2026
Non-Registrant:					
AEGCo	Pollution Control Bonds		22 (a)	Variable	2025
AEGCo	Pollution Control Bonds		23 (a)	Variable	2025
TCC	Pollution Control Bonds		60 (a)	1.125	2012
Total Issuances		$	1,128 (b)		

(a) These pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on our condensed balance sheets.

(b) Amount indicated on the statement of cash flows of $1,118 million is net of issuance costs and premium or discount.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Pollution Control Bonds	$ 75	Variable	2036
APCo	Pollution Control Bonds	54	Variable	2042
APCo	Pollution Control Bonds	50	Variable	2042
APCo	Pollution Control Bonds	50	Variable	2036
APCo	Senior Unsecured Notes	250	5.55	2011
I&M	Pollution Control Bonds	52	Variable	2021
I&M	Pollution Control Bonds	25	Variable	2019
I&M	Notes Payable	13	5.16	2014
I&M	Notes Payable	15	5.44	2013
I&M	Notes Payable	17	Variable	2015
OPCo	Pollution Control Bonds	65	Variable	2036
OPCo	Pollution Control Bonds	50	Variable	2014
OPCo	Pollution Control Bonds	50	Variable	2014
PSO	Senior Unsecured Notes	200	6.00	2032
PSO	Senior Unsecured Notes	75	4.70	2011
SWEPCo	Pollution Control Bonds	41	4.50	2011
Non-Registrant:				
AEP Subsidiaries	Notes Payable	13	Variable	2017
AEP Subsidiaries	Notes Payable	6	Variable	2011
AEP Subsidiaries	Notes Payable	1	8.03	2026
AEP Subsidiaries	Notes Payable	1	7.59	2026
AEGCo	Other Long-term Debt	85	Variable	2011
AEGCo	Senior Unsecured Notes	7	6.33	2037
AEGCo	Pollution Control Bonds	22	4.15	2025
AEGCo	Pollution Control Bonds	23	4.15	2025
TCC	Securitization Bonds	60	5.96	2013

TCC	Securitization Bonds		99	4.98	2013
TCC	Pollution Control Bonds		121	5.125	2011
Total Retirements and Principal Payments		$	1,520		

In October 2011, I&M retired $29 million of Notes Payable related to DCC Fuel.

In October 2011, APCo remarketed $100 million of 2% Pollution Control Bonds due in 2014.

As of September 30, 2011, trustees held, on our behalf, $478 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013. We have the option to defer interest payments on the 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 anticipate any deferral of those interest payments in the foreseeable future.

Utility Subsidiaries' Restrictions

Various 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.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Short-term Debt

Our outstanding short-term debt was as follows:

	September 30, 2011		December 31, 2010	
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
Securitized Debt for Receivables (b)	$ 750	0.27 %	$ 690	0.31 %
Commercial Paper	529	0.42 %	650	0.52 %
Line of Credit – Sabine Mining Company (c)	-	- %	6	2.15 %
Total Short-term Debt	$ 1,279		$ 1,346	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 4.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

In July 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.23 %	0.41 %	0.27 %	0.32 %
Net Uncollectible Accounts Receivable Written Off	$ 11	$ 9	$ 28	$ 16

	September 30, 2011	December 31, 2010
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,005	$ 923
Total Principal Outstanding	750	690
Delinquent Securitized Accounts Receivable	45	50
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	20	26
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	297	354

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

12. COST REDUCTION INITIATIVES

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of $293 million to Other Operation expense during the second quarter of 2010 primarily related to severance benefits as the result of headcount reduction initiatives.

The following table shows the cost reduction activity for the nine months ended September 30, 2011:

	Total (in millions)
Balance as of December 31, 2010	$ 17
Incurred	-
Settled	(12)
Adjustments	(1)
	$ 4

Balance as of September 30, 2011

The remaining accruals are included primarily in Other Current Liabilities on the condensed balance sheets.

82

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Regulatory Activity

Virginia Regulatory Activity

In March 2011, APCo filed a generation and distribution base rate request with the Virginia SCC to increase annual base rates by $126 million based upon an 11.65% return on common equity to be effective no later than February 2012. The return on common equity includes a requested 0.5% renewable portfolio standards incentive as allowed by law. APCo proposed to mitigate the requested base rate increase by $51 million by maintaining current depreciation rates until the next biennial filing. If approved, APCo's net base rate increase would be $75 million. In August 2011, the Virginia Attorney General and the Virginia SCC staff filed testimony recommending no increase in annual base rates and a $31 million increase in annual base rates, respectively. Hearings were held in September 2011. A decision from the Virginia SCC is pending. See "2011 Virginia Biennial Base Rate Case" section of Note 3.

West Virginia Regulatory Activity

In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $46 million based upon a 10% return on common equity. The approved settlement agreement also resulted in a pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility in the first quarter of 2011. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and $14 million of previously expensed costs related to the 2010 cost reduction initiatives, each over a period of seven years. See "2010 West Virginia Base Rate Case" section of Note 3.

In a November 2009 proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. Merger approvals from the WVPSC, the Virginia SCC and the FERC are required. No merger approval filings have been made. See "WPCo Merger with APCo" section of Note 3.

Acquisition of Dresden Plant

During the first quarter of 2011, APCo and AEGCo filed with the Virginia and West Virginia regulatory commissions seeking approval for APCo's purchase of the partially completed Dresden Plant from AEGCo at cost. In June 2011 and July 2011, the WVPSC and the Virginia SCC, respectively, issued orders approving the acquisition. APCo purchased the Dresden Plant from AEGCo in August 2011 for $302 million. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. When completed, the Dresden Plant will have a generating capacity of 580 MW.

Litigation and Environmental Issues

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 166. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 232 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions of KWHs)			
Retail:				
Residential	2,854	2,990	9,180	9,810
Commercial	1,861	1,880	5,254	5,416
Industrial	2,738	2,736	8,056	7,922
Miscellaneous	204	204	617	639
Total Retail	7,657	7,810	23,107	23,787
Wholesale	3,072	2,436	7,235	5,555
Total KWHs	10,729	10,246	30,342	29,342

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in degree days)			
Actual - Heating (a)	3	-	1,389	1,611
Normal - Heating (b)	3	3	1,440	1,443
Actual - Cooling (c)	955	971	1,425	1,511
Normal - Cooling (b)	807	798	1,161	1,146

(a) Eastern 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.

Third Quarter of 2011 Compared to Third Quarter of 2010

Reconciliation of Third Quarter of 2010 to Third Quarter of 2011
Net Income
(in millions)

Third Quarter of 2010	$	50
Changes in Gross Margin:		
Retail Margins		3
Off-system Sales		(1)
Transmission Revenues		1
Total Change in Gross Margin		3
Changes in Expenses and Other:		
Depreciation and Amortization		8
Other Income		4
Interest Expense		2
Total Change in Expenses and Other		14
Income Tax Expense		(14)
Third Quarter of 2011	$	53

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 $3 million primarily due to the following:
  - A $22 million increase due to higher base rates in Virginia and West Virginia.
  - A $19 million increase due to lower capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.

  These increases were partially offset by:
  - A $23 million decrease due to the expiration of E&R cost recovery in Virginia.
  - A $6 million decrease in residential and commercial margins primarily due to lower non-weather related usage.
  - A $5 million decrease in other variable electric generation expenses.

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

- Depreciation and Amortization expenses decreased $8 million primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia, partially offset by an increased depreciation base resulting from environmental upgrades at the Amos Plant.
- Other Income increased $4 million primarily due to an increase in the equity component of AFUDC as a result of construction at the Dresden Plant and for interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- Income Tax Expense increased $14 million primarily due to an increase in pretax book income and state income tax adjustments.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Reconciliation of Nine Months Ended September 30, 2010 to Nine Months Ended
September 30, 2011
Net Income
(in millions)

Nine Months Ended September 30, 2010	$	101
Changes in Gross Margin:		
Retail Margins		(46)
Off-system Sales		3
Transmission Revenues		7
Other Revenues		(1)
Total Change in Gross Margin		(37)
Changes in Expenses and Other:		
Other Operation and Maintenance		60
Depreciation and Amortization		22
Taxes Other Than Income Taxes		3
Carrying Costs Income		(6)
Other Income		5
Interest Expense		(1)
Total Change in Expenses and Other		83
Income Tax Expense		(24)
Nine Months Ended September 30, 2011	$	123

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

· Retail Margins decreased $46 million primarily due to the following:
  · A $60 million decrease due to the expiration of E&R cost recovery in Virginia.
  · A $27 million decrease in other variable electric generation expenses.
  · A $21 million decrease in weather-related usage primarily due to a 14% decrease in heating degree days and a 6% decrease in cooling degree days.
  · A $16 million decrease in residential and commercial margins primarily due to lower non-weather related usage.

  These decreases were partially offset by:
  · A $46 million increase due to lower capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
  · A $41 million increase due to higher base rates in Virginia and West Virginia.
  · An $8 million increase primarily due to formula rate increases in Virginia.

· Margins from Off-system Sales increased $3 million primarily due to higher physical sales volumes, partially offset by lower trading and marketing margins.

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Transmission Revenues increased $7 million primarily due to the Transmission Agreement modification effective November 2010.

87

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

- Other Operation and Maintenance expenses decreased $60 million primarily due to the following:
- A $54 million decrease due to the second quarter 2010 write-off of the Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.
- A $51 million decrease due to expenses related to the cost reduction initiatives recorded in the second quarter of 2010.
  - A $32 million decrease due to the first quarter 2011 deferral of 2010 storm costs and costs related to 2010 cost reduction initiatives. These costs were deferred as a result of the approved modified settlement agreement of APCo's West Virginia base rate case in March 2011.
  - A $6 million decrease in steam maintenance expenses primarily due to a planned outage at the Amos Plant in 2010.
  - A $6 million decrease in transmission expenses primarily due to the expiration of E&R amortization in Virginia.

  These decreases were partially offset by:
  - A $41 million increase due to the first quarter 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $25 million increase due to the second quarter 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
  - A $15 million increase in transmission expenses primarily due to the Transmission Agreement modification effective November 2010.
  - A $14 million increase in storm-related expenses.
- Depreciation and Amortization expenses decreased $22 million primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia, partially offset by an increased depreciation base resulting from environmental upgrades at the Amos Plant.
- Taxes Other Than Income Taxes decreased $3 million primarily due to recording a West Virginia franchise tax audit settlement and additional employer payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
- Carrying Costs Income decreased $6 million primarily due to decreased environmental deferrals in Virginia.
- Other Income increased $5 million primarily due to an increase in the equity component of AFUDC as a result of construction at the Dresden Plant and for interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- Income Tax Expense increased $24 million primarily due to an increase in pretax book income and state income tax adjustments.

FINANCIAL CONDITION

LIQUIDITY

APCo participates in the Utility Money Pool, which provides access to AEP's liquidity. APCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 232 for additional discussion of liquidity.

Credit Ratings

APCo's access to capital markets may depend on its credit ratings. In addition, a credit rating downgrade of APCo by one of the rating agencies could increase APCo's borrowing costs. Failure to maintain investment grade ratings may constrain APCo's ability to participate in the Utility Money Pool or the amount of APCo's receivables securitized by AEP Credit. Counterparty concerns about APCo's credit quality could subject APCo to additional collateral demands under adequate assurance clauses under derivative and non-derivative energy contracts.

CASH FLOW

Cash flows for the nine months ended September 30, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 951	$ 2,006
Net Cash Flows from Operating Activities	645,824	567,464
Net Cash Flows Used for Investing Activities	(672,514)	(363,246)
Net Cash Flows from (Used for) Financing Activities	28,408	(204,023)
Net Increase in Cash and Cash Equivalents	1,718	195
Cash and Cash Equivalents at End of Period	$ 2,669	$ 2,201

Operating Activities

Net Cash Flows from Operating Activities were $646 million in 2011. APCo produced Net Income of $123 million during the period and had noncash expense items of $205 million for Depreciation and Amortization and $185 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $133 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory. The $124 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued unbilled revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The $73 million outflow from Accounts Payable was primarily due to decreased energy purchases and reduced operation and maintenance expenses. The $54 million outflow from Accrued Taxes, Net was primarily due to decreased accruals related to federal income taxes. The $21 million outflow from Fuel Over/Under-Recovery, Net was primarily due to a net under-recovery of fuel costs in both Virginia and West Virginia.

Net Cash Flows from Operating Activities were $567 million in 2010. APCo produced Net Income of $101 million during the period and had noncash expense items of $227 million for Depreciation and Amortization and $53 million for Deferred Income Taxes. APCo contributed $32 million to the qualified pension trust. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $133 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory and a decrease in the average cost of coal per ton. The $114 million outflow from Accounts Payable was primarily due to payments for storm costs accrued in fourth quarter of 2009 and decreased purchases of energy from the system pool. The $107 million inflow from Accrued Taxes, Net includes a third quarter 2010 income tax refund of $170 million as a result of a federal net income tax operating loss in 2009 that was carried back to 2007 and 2008. Items contributing to the net income tax operating loss include bonus depreciation and the favorable impact of a change in tax accounting method related to units of property. The $94 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued unbilled revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies.

Investing Activities

Net Cash Flows Used for Investing Activities during 2011 and 2010 were $673 million and $363 million, respectively. Construction Expenditures of $300 million and $363 million in 2011 and 2010, respectively, were primarily for environmental upgrades, as well as projects to improve generation and service reliability for transmission and distribution. Environmental upgrades include FGD projects at the Amos Plant. Acquisitions of Assets in 2011 of $302 million were due to APCo's purchase of the Dresden Plant from AEGCo in August 2011. During 2011, APCo had a net increase of $82 million in loans to the Utility Money Pool.

Financing Activities

Net Cash Flows from Financing Activities were $28 million in 2011. APCo issued $350 million of Senior Unsecured Notes and $295 million of Pollution Control Bonds, partially offset by the retirement of $250 million of Senior Unsecured Notes and $230 million of Pollution Control Bonds. APCo had a net decrease of $128 million in borrowings from the Utility Money Pool. APCo also received capital contributions from the Parent of $100 million. In addition, APCo paid $98 million in common stock dividends.

Net Cash Flows Used for Financing Activities were $204 million in 2010. APCo issued $300 million of Senior Unsecured Notes and $68 million of Pollution Control Bonds, partially offset by the retirement of $150 million of Senior Unsecured Notes, $100 million of Notes Payable – Affiliated and $50 million of Pollution Control Bonds. APCo had a net decrease of $174 million in borrowings from the Utility Money Pool. In addition, APCo paid $88 million in common stock dividends.

Long-term debt issuances, retirements and principal payments made during the first nine months of 2011 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	350,000	4.60	2021
Pollution Control Bonds		65,350	2.00	2012
Pollution Control Bonds		75,000 (a)	Variable	2036
Pollution Control Bonds		50,275 (a)	Variable	2036
Pollution Control Bonds		54,375 (a)	Variable	2042
Pollution Control Bonds		50,000 (a)	Variable	2042

(a) These pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year – Nonaffiliated on APCo’s condensed balance sheets.

Retirements and Principal Payments

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	75,000	Variable	2036
Pollution Control Bonds		50,275	Variable	2036
Pollution Control Bonds		54,375	Variable	2042
Pollution Control Bonds		50,000	Variable	2042
Senior Unsecured Notes		250,000	5.55	2011
Land Note		16	13.718	2026

In October 2011, APCo remarketed $100 million of 2% Pollution Control Bonds due in 2014.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2010 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2010 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 232 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 232 for a discussion of market risk.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Three Months Ended 2011	Three Months Ended 2010	Nine Months Ended 2011	Nine Months Ended 2010
REVENUES				
Electric Generation, Transmission and Distribution	$757,366	$754,940	$2,175,163	$2,234,070
Sales to AEP Affiliates	98,419	83,675	259,641	229,811
Other Revenues	2,551	2,007	6,797	6,638
TOTAL REVENUES	858,336	840,622	2,441,601	2,470,519
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	230,318	190,538	595,597	540,794
Purchased Electricity for Resale	57,370	60,751	195,715	181,370
Purchased Electricity from AEP Affiliates	222,164	243,772	630,014	690,881
Other Operation	80,376	77,138	268,269	338,085
Maintenance	50,172	53,276	139,628	130,446
Depreciation and Amortization	68,749	76,737	205,492	227,327
Taxes Other Than Income Taxes	26,471	26,350	79,542	82,585
TOTAL EXPENSES	735,620	728,562	2,114,257	2,191,488
OPERATING INCOME	122,716	112,060	327,344	279,031
Other Income (Expense):				
Interest Income	2,477	210	3,559	1,163
Carrying Costs Income	7,579	7,565	17,560	23,627
Allowance for Equity Funds Used During Construction	2,451	436	4,546	1,727
Interest Expense	(51,196)	(52,734)	(157,323)	(156,292)
INCOME BEFORE INCOME TAX EXPENSE	84,027	67,537	195,686	149,256
Income Tax Expense	31,223	17,466	72,275	48,522
NET INCOME	52,804	50,071	123,411	100,734
Preferred Stock Dividend Requirements Including Capital Stock Expense	199	225	599	675
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$52,605	$49,846	$122,812	$100,059

The common stock of APCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$260,458	$1,475,393	$1,085,980	$ (50,254)	$2,771,577
Common Stock Dividends			(88,000)		(88,000)
Preferred Stock Dividends			(599)		(599)
Capital Stock Expense		78	(76)		2
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,682,980
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,953				(3,627)	(3,627)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,685				3,129	3,129
NET INCOME			100,734		100,734
TOTAL COMPREHENSIVE INCOME					100,236
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2010	$260,458	$1,475,471	$1,098,039	$ (50,752)	$2,783,216
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$260,458	$1,475,496	$1,133,748	$ (48,023)	$2,821,679
Capital Contribution from Parent		100,000			100,000
Common Stock Dividends			(97,500)		(97,500)
Preferred Stock Dividends			(599)		(599)
Gain on Reacquired Preferred Stock		3			3
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,823,583
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $413				767	767
Amortization of Pension and OPEB Deferred					

Costs, Net of Tax of $1,255				2,332	2,332
NET INCOME			123,411		123,411
TOTAL COMPREHENSIVE INCOME					126,510
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$260,458	$1,575,499	$1,159,060	$ (44,924)	$2,950,093

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

93

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$2,669	$951
Advances to Affiliates	81,825	-
Accounts Receivable:		
Customers	142,826	166,878
Affiliated Companies	97,664	145,972
Accrued Unbilled Revenues	56,196	108,210
Miscellaneous	1,033	3,090
Allowance for Uncollectible Accounts	(5,571)	(6,667)
Total Accounts Receivable	292,148	417,483
Fuel	90,260	230,697
Materials and Supplies	97,313	89,370
Risk Management Assets	30,290	53,242
Accrued Tax Benefits	109,910	104,435
Regulatory Asset for Under-Recovered Fuel Costs	28,635	18,300
Prepayments and Other Current Assets	23,970	35,811
TOTAL CURRENT ASSETS	757,020	950,289
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,118,671	4,736,150
Transmission	1,901,047	1,852,415
Distribution	2,816,694	2,740,752
Other Property, Plant and Equipment	356,081	348,013
Construction Work in Progress	582,528	562,280
Total Property, Plant and Equipment	10,775,021	10,239,610
Accumulated Depreciation and Amortization	2,975,417	2,843,087
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,799,604	7,396,523
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,498,907	1,486,625
Long-term Risk Management Assets	24,137	38,420
Deferred Charges and Other Noncurrent Assets	105,993	125,296
TOTAL OTHER NONCURRENT ASSETS	1,629,037	1,650,341
TOTAL ASSETS	$10,185,661	$9,997,153

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 128,331
Accounts Payable:		
General	170,319	223,144
Affiliated Companies	138,201	166,884
Long-term Debt Due Within One Year – Nonaffiliated	545,024	479,672
Risk Management Liabilities	19,133	27,993
Customer Deposits	60,091	58,451
Deferred Income Taxes	38,113	44,180
Accrued Taxes	55,183	75,619
Accrued Interest	63,559	57,871
Other Current Liabilities	90,275	93,286
TOTAL CURRENT LIABILITIES	1,179,898	1,355,431
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,181,045	3,081,469
Long-term Risk Management Liabilities	7,148	10,873
Deferred Income Taxes	1,802,238	1,642,072
Regulatory Liabilities and Deferred Investment Tax Credits	571,718	562,381
Employee Benefits and Pension Obligations	282,360	306,460
Deferred Credits and Other Noncurrent Liabilities	193,425	199,041
TOTAL NONCURRENT LIABILITIES	6,037,934	5,802,296
TOTAL LIABILITIES	7,217,832	7,157,727
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,736	17,747
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,575,499	1,475,496
Retained Earnings	1,159,060	1,133,748
Accumulated Other Comprehensive Income (Loss)	(44,924)	(48,023)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,950,093	2,821,679
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$ 10,185,661	$ 9,997,153

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$123,411	$100,734
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	205,492	227,327
Deferred Income Taxes	184,986	52,798
Carrying Costs Income	(17,560)	(23,627)
Allowance for Equity Funds Used During Construction	(4,546)	(1,727)
Mark-to-Market of Risk Management Contracts	13,161	(2,573)
Pension Contributions to Qualified Plan Trust	(14,700)	(31,952)
Property Taxes	19,231	19,660
Fuel Over/Under-Recovery, Net	(20,603)	(17,136)
Change in Other Noncurrent Assets	(5,856)	29,275
Change in Other Noncurrent Liabilities	15,714	4,558
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	124,404	93,787
Fuel, Materials and Supplies	132,579	132,801
Accounts Payable	(72,682)	(113,912)
Accrued Taxes, Net	(54,214)	107,404
Other Current Assets	13,023	(4,416)
Other Current Liabilities	3,984	(5,537)
Net Cash Flows from Operating Activities	645,824	567,464
INVESTING ACTIVITIES		
Construction Expenditures	(300,357)	(362,792)
Change in Advances to Affiliates, Net	(81,825)	-
Acquisitions of Assets	(302,217)	(9,595)
Other Investing Activities	11,885	9,141
Net Cash Flows Used for Investing Activities	(672,514)	(363,246)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100,000	-
Issuance of Long-term Debt – Nonaffiliated	640,027	363,736
Change in Advances from Affiliates, Net	(128,331)	(174,433)
Retirement of Long-term Debt – Nonaffiliated	(479,666)	(200,014)
Retirement of Long-term Debt – Affiliated	-	(100,000)
Retirement of Cumulative Preferred Stock	(8)	(4)
Principal Payments for Capital Lease Obligations	(5,546)	(5,350)
Dividends Paid on Common Stock	(97,500)	(88,000)
Dividends Paid on Cumulative Preferred Stock	(599)	(599)
Other Financing Activities	31	641
Net Cash Flows from (Used for) Financing Activities	28,408	(204,023)

Net Increase in Cash and Cash Equivalents	1,718	195
Cash and Cash Equivalents at Beginning of Period	951	2,006
Cash and Cash Equivalents at End of Period	$2,669	$2,201
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$145,969	$140,391
Net Cash Paid (Received) for Income Taxes	(74,384)	(140,113)
Noncash Acquisitions Under Capital Leases	697	22,623
Government Grants Included in Accounts Receivable at September 30,	137	-
Construction Expenditures Included in Current Liabilities at September 30,	60,265	52,863

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to APCo’s condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page 166.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Regulatory Activity

2009 – 2011 ESP

In April 2011, the Supreme Court of Ohio issued an opinion addressing the aspects of the PUCO's 2009 decision that were challenged and remanded certain issues back to the PUCO. In October 2011, the PUCO issued an order in the remand proceeding. The order required CSPCo to refund POLR charges which were collected subject to refund since June 2011. As a result, in the third quarter of 2011, CSPCo recorded a pretax refund provision of $34 million on the condensed statements of income. In addition, CSPCo filed its 2010 SEET filings with the PUCO. Based upon the approach in the PUCO 2009 order, management does not currently believe that CSPCo will have any significantly excessive earnings. In October 2011, the Ohio Consumers' Counsel and the Ohio Energy Group filed testimony that recommended CSPCo refund up to $41 million of its 2010 earnings. Also in October 2011, the PUCO staff filed testimony that recommended CSPCo refund $21 million of its 2010 earnings. See "Ohio Electric Security Plan Filings" section of Note 3.

January 2012 – May 2016 ESP

In January 2011, CSPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation. In September 2011, a stipulation agreement was filed with the PUCO which involved various issues pending before the PUCO, including the approval of the CSPCo/OPCo merger and the recovery of deferred fuel until securitized. Under the stipulation agreement, rates would be effective with the first billing cycle of January 2012 through the last billing cycle of May 2016. Prior to June 2015, CSPCo's SSO customers continue to pay the tariff rate for non-fuel generation and the fuel adjustment clause. Beginning in June 2015, CSPCo will use results from a competitive bidding process performed prior to January 2015 to meet its SSO obligation through May 2016. The stipulation agreement proposed a corporate separation plan of CSPCo's generation assets to complete the transition to a fully competitive generation market by June 2015. In addition, to further develop customer choice and facilitate the transition to market generation pricing, CSPCo will provide 21% of its generation capacity in 2012, 29% to 31% of its generation capacity in 2013 and 41% of its generation capacity beginning in 2014 through June 2015 to competitive retail suppliers at a charge based on the Reliability Pricing Model auction-clearing prices and the remainder at a discounted cost-based price.

The stipulation agreement also proposed a termination or modification of the Interconnection Agreement. Finally, the stipulation agreement provides for certain CSPCo contingent contributions and established a Distribution Investment Rider beginning January 2012 through May 2015 to recover post-2000 distribution investment with certain limitations. See "Ohio Electric Security Plan Filings," "Proposed CSPCo and OPCo Merger" and "Possible Termination of the Interconnection Agreement" sections of Note 3.

Ohio Distribution Base Rate Case

In February 2011, CSPCo filed with the PUCO for an annual increase in distribution rates of $34 million. The requested increase is based upon an 11.15% return on common equity to be effective January 2012. In addition to the annual increase, CSPCo requested recovery of the projected December 31, 2012 balance of certain distribution regulatory assets of $216 million, including carrying costs, to be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013. The PUCO staff filed testimony that recommended a rate reduction in the range of $2 million to $10 million plus recovery of the deferred distribution regulatory assets subject to a review of the carrying costs. A decision from the PUCO is expected in the fourth quarter of 2011. See “2011 Ohio Distribution Base Rate Case” section of Note 3.

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. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. In July 2011, the FERC issued an order approving the proposed merger. In September 2011, a stipulation agreement was filed with the PUCO which recommended CSPCo merge into OPCo by the end of 2011. A decision from the PUCO is expected in the fourth quarter of 2011. See “January 2012 - May 2016 ESP” and “Proposed CSPCo and OPCo Merger” sections of Note 3.

Ohio Customer Choice

In CSPCo’s service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As a result, in comparison to the third quarter of 2010 and the first nine months of 2010, CSPCo lost approximately $34 million and $83 million, respectively, of generation and transmission related gross margin. CSPCo is recovering a portion of lost margins through collection of transmission revenues from competitive CRES providers and off-system sales.

Litigation and Environmental Issues

In the ordinary course of business, CSPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 166. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Executive Overview” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page 232 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions of KWHs)			
Retail:				
Residential	2,157	2,213	5,879	6,006
Commercial	2,368	2,292	6,481	6,506
Industrial	1,391	1,190	4,020	3,458
Miscellaneous	13	12	40	39
Total Retail	5,929	5,707	16,420	16,009

Wholesale	1,644	1,188	3,684	2,544
Total KWHs	7,573	6,895	20,104	18,553

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in degree days)			
Actual - Heating (a)	3	-	2,052	2,035
Normal - Heating (b)	6	6	1,953	1,956
Actual - Cooling (c)	860	876	1,230	1,306
Normal - Cooling (b)	727	715	1,029	1,011

(a) Eastern 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.

Third Quarter of 2011 Compared to Third Quarter of 2010

Reconciliation of Third Quarter of 2010 to Third Quarter of 2011
Net Income
(in millions)

Third Quarter of 2010	$	107
Changes in Gross Margin:		
Retail Margins		(53)
Off-system Sales		6
Transmission Revenues		1
Other Revenues		(2)
Total Change in Gross Margin		(48)
Changes in Expenses and Other:		
Other Operation and Maintenance		(1)
Taxes Other Than Income Taxes		1
Carrying Costs Income		1
Other Income		2
Interest Expense		1
Total Change in Expenses and Other		4
Income Tax Expense		18
Third Quarter of 2011	$	81

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

- Retail Margins decreased $53 million due to the following:
  - A $34 million decrease attributable to customers switching to alternative competitive retail electric service (CRES) providers.
  - A $33 million refund provision for POLR charges as a result of the October 2011 PUCO remand order.
  - An $8 million decrease in residential and industrial margins primarily due to a change in the customer mix resulting in lower realizations.
  - A $3 million decrease in capacity settlements under the Interconnection Agreement.

  These decreases were partially offset by:
  - A $10 million net increase in transmission rider revenues.
  - An $8 million increase related to Environmental Investment Carrying Charge Rider (EICCR) revenues.
- Margins from Off-system Sales increased $6 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.

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

- Other Operation and Maintenance expenses increased $1 million primarily due to:
  - A $2 million increase due to the third quarter 2011 write-off of allocated Front-End Engineering and Design (FEED) study costs related to the Mountaineer Carbon Capture Project.
  - A $2 million donation to the Ohio Business Development Coalition for JobsOhio.
  - A $2 million increase in distribution overhead line maintenance expenses primarily due to increased vegetation management and 2011 storm costs, partially offset by the increased under-recovery of the Enhanced Service Reliability Plan (ESRP).
  - A $1 million increase in remitted Universal Service Fund surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers.
  - A $1 million increase in recoverable PJM expenses.

  These increases were offset by:
  - A $10 million decrease in transmission expense primarily due to the Transmission Agreement modification effective November 2010, a portion of which is included in the Ohio Transmission Cost Recovery Rider.
- Other Income increased $2 million due to interest income recorded in the third quarter 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- Income Tax Expense decreased $18 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Reconciliation of Nine Months Ended September 30, 2010 to Nine Months Ended
September 30, 2011
Net Income
(in millions)

Nine Months Ended September 30, 2010	$	211	
Changes in Gross Margin:			
Retail Margins		(73	)
Off-system Sales		38	
Transmission Revenues		2	
Other Revenues		(2	)
Total Change in Gross Margin		(35	)
Changes in Expenses and Other:			
Other Operation and Maintenance		32	
Depreciation and Amortization		(4	)
Taxes Other Than Income Taxes		(2	)
Carrying Costs Income		3	
Other Income		2	
Interest Expense		3	
Total Change in Expenses and Other		34	
Income Tax Expense		4	
Nine Months Ended September 30, 2011	$	214	

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

- Retail Margins decreased $73 million primarily due to:
  - An $83 million decrease attributable to customers switching to alternative CRES providers.
  - A $33 million refund provision for POLR charges as a result of the October 2011 PUCO remand order.
  - A $6 million decrease in transmission recovery revenues.
  - A $6 million decrease in capacity settlements under the Interconnection Agreement.

  These decreases were partially offset by:
  - A $19 million increase in revenue due to the implementation of PUCO approved rider rates in June 2010 related to the Energy Efficiency & Peak Demand Reduction (EE/PDR) Programs. This increase in Retail Margins was offset by a corresponding increase in Other Operation and Maintenance as discussed below.
  - A $15 million increase related to EICCR revenues.
  - A $10 million increase associated with the final 2009 SEET order.
- Margins from Off-system Sales increased $38 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.

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

- Other Operation and Maintenance expenses decreased $32 million primarily due to:
  - A $31 million decrease due to expenses related to the cost reduction initiatives recorded in the second quarter of 2010.
  - A $26 million decrease in transmission expense primarily due to the Transmission Agreement modification effective November 2010, a portion of which is included in the Ohio Transmission Cost Recovery Rider.
  - A $13 million decrease in recoverable PJM expenses.

  These decreases were partially offset by:
  - A $19 million increase in expenses due to the implementation of PUCO approved EE/PDR programs. This increase in Other Operation and Maintenance expense was offset by a corresponding increase in Retail Margins as discussed above.
  - A $15 million increase in plant maintenance and operation expenses primarily related to work performed at the Stuart, Waterford and Conesville plants.
  - A $4 million increase in distribution overhead line maintenance expenses primarily due to increased vegetation management and 2011 storm costs, partially offset by the increased under-recovery of Enhanced Service Reliability Plan (ESRP).
  - A $2 million increase due to the third quarter 2011 write-off of allocated FEED study costs related to the Mountaineer Carbon Capture Project.
- Depreciation and Amortization increased $4 million primarily due to the following:
  - A $4 million increase as a result of recognizing deferred debt and equity carrying charges on deferred fuel as permitted under the final 2009 SEET order.
  - A $1 million increase primarily due to the amortization of debt and equity carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income as discussed below.

    These increases were partially offset by:
  - A $1 million decrease due to the completion of amortization of MonPower litigation in March 2011.
- Carrying Costs Income increased $3 million due to equity carrying costs as a result of the 2009 SEET refund order and due to the recognition of equity carrying costs income on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity carrying costs income was offset by amounts in Depreciation and Amortization discussed above.
- Interest Expense decreased $3 million primarily as a result of a long-term debt retirement in December 2010.
- Income Tax Expense decreased $4 million primarily due to other book/tax differences which are accounted for on a flow-through basis.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2010 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 232 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 232 for a discussion of market risk.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2011	2010	2011	2010
REVENUES				
Electric Generation, Transmission and Distribution	$603,622	$616,823	$1,589,648	$1,621,112
Sales to AEP Affiliates	46,793	30,765	125,939	66,687
Other Revenues	470	806	1,359	2,138
TOTAL REVENUES	650,885	648,394	1,716,946	1,689,937
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	157,783	99,883	364,456	319,614
Purchased Electricity for Resale	25,244	28,116	73,646	67,899
Purchased Electricity from AEP Affiliates	129,315	134,467	336,295	324,553
Other Operation	83,342	86,360	219,522	266,915
Maintenance	26,767	23,196	88,290	72,593
Depreciation and Amortization	38,874	38,644	117,831	113,733
Taxes Other Than Income Taxes	49,812	50,884	144,089	142,235
TOTAL EXPENSES	511,137	461,550	1,344,129	1,307,542
OPERATING INCOME	139,748	186,844	372,817	382,395
Other Income (Expense):				
Interest Income	2,296	385	2,646	694
Carrying Costs Income	3,193	2,028	9,115	6,212
Allowance for Equity Funds Used During Construction	572	267	1,890	1,502
Interest Expense	(20,905)	(21,382)	(60,854)	(64,257)
INCOME BEFORE INCOME TAX EXPENSE	124,904	168,142	325,614	326,546
Income Tax Expense	43,391	61,085	112,015	115,723
NET INCOME	81,513	107,057	213,599	210,823
Capital Stock Expense	25	39	75	118
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$81,488	$107,018	$213,524	$210,705

The common stock of CSPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$41,026	$580,663	$788,139	$ (49,993)	$1,359,835
Common Stock Dividends			(77,500)		(77,500)
Capital Stock Expense		118	(118)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,282,335
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $462				(857)	(857)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,000				1,857	1,857
NET INCOME			210,823		210,823
TOTAL COMPREHENSIVE INCOME					211,823
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2010	$41,026	$580,781	$921,344	$ (48,993)	$1,494,158
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$41,026	$580,812	$915,713	$ (51,336)	$1,486,215
Common Stock Dividends			(187,500)		(187,500)
Capital Stock Expense		75	(75)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,298,715
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $74				138	138
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,187				2,204	2,204
NET INCOME			213,599		213,599
TOTAL COMPREHENSIVE INCOME					215,941

TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$41,026	$580,887	$941,737	$ (48,994)	$1,514,656

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,834	$ 509
Other Cash Deposits	17	2,260
Advances to Affiliates	156,606	54,202
Accounts Receivable:		
Customers	35,946	50,187
Affiliated Companies	41,500	66,788
Accrued Unbilled Revenues	11,740	32,821
Miscellaneous	5,834	14,374
Allowance for Uncollectible Accounts	(1,524)	(1,584)
Total Accounts Receivable	93,496	162,586
Fuel	50,022	72,882
Materials and Supplies	42,800	42,033
Emission Allowances	23,883	28,486
Risk Management Assets	18,445	23,774
Accrued Tax Benefits	14,943	8,797
Margin Deposits	8,867	14,762
Prepayments and Other Current Assets	8,394	26,864
TOTAL CURRENT ASSETS	419,307	437,155
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,744,384	2,686,294
Transmission	679,544	662,312
Distribution	1,837,705	1,796,023
Other Property, Plant and Equipment	207,235	203,593
Construction Work in Progress	147,900	172,793
Total Property, Plant and Equipment	5,616,768	5,521,015
Accumulated Depreciation and Amortization	2,021,245	1,927,112
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,595,523	3,593,903
OTHER NONCURRENT ASSETS		
Regulatory Assets	314,149	298,111
Long-term Risk Management Assets	14,887	22,089
Deferred Charges and Other Noncurrent Assets	72,746	152,932
TOTAL OTHER NONCURRENT ASSETS	401,782	473,132
TOTAL ASSETS	$ 4,416,612	$ 4,504,190

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$83,974	$98,925
Affiliated Companies	62,740	78,617
Long-term Debt Due Within One Year – Nonaffiliated	194,500	-
Risk Management Liabilities	11,746	15,967
Customer Deposits	29,975	29,441
Accrued Taxes	120,393	226,572
Accrued Interest	25,212	22,533
Other Current Liabilities	79,516	111,868
TOTAL CURRENT LIABILITIES	608,056	583,923
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,244,539	1,438,830
Long-term Risk Management Liabilities	4,382	6,223
Deferred Income Taxes	661,637	604,828
Regulatory Liabilities and Deferred Investment Tax Credits	171,936	163,888
Employee Benefits and Pension Obligations	129,399	136,643
Deferred Credits and Other Noncurrent Liabilities	82,007	83,640
TOTAL NONCURRENT LIABILITIES	2,293,900	2,434,052
TOTAL LIABILITIES	2,901,956	3,017,975
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,887	580,812
Retained Earnings	941,737	915,713
Accumulated Other Comprehensive Income (Loss)	(48,994)	(51,336)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,514,656	1,486,215
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$4,416,612	$4,504,190

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$213,599	$210,823
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	117,831	113,733
Deferred Income Taxes	64,204	30,333
Carrying Costs Income	(9,115)	(6,212)
Allowance for Equity Funds Used During Construction	(1,890)	(1,502)
Mark-to-Market of Risk Management Contracts	6,723	(6,397)
Property Taxes	83,427	71,795
Fuel Over/Under-Recovery, Net	14,236	22,912
Change in Other Noncurrent Assets	(17,457)	(5,506)
Change in Other Noncurrent Liabilities	4,316	(14,413)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	61,290	11,164
Fuel, Materials and Supplies	25,278	6,419
Accounts Payable	(27,077)	(20,468)
Accrued Taxes, Net	(116,972)	(49,443)
Other Current Assets	9,873	6,110
Other Current Liabilities	(28,429)	(219)
Net Cash Flows from Operating Activities	399,837	369,129
INVESTING ACTIVITIES		
Construction Expenditures	(137,360)	(148,441)
Change in Other Cash Deposits	2,243	13,890
Change in Advances to Affiliates, Net	(102,404)	(182,225)
Proceeds from Sales of Assets	6,855	4,278
Other Investing Activities	22,028	(586)
Net Cash Flows Used for Investing Activities	(208,638)	(313,084)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	149,443
Change in Advances from Affiliates, Net	-	(24,202)
Retirement of Long-term Debt – Affiliated	-	(100,000)
Principal Payments for Capital Lease Obligations	(2,519)	(3,322)
Dividends Paid on Common Stock	(187,500)	(77,500)
Other Financing Activities	145	119
Net Cash Flows Used for Financing Activities	(189,874)	(55,462)
Net Increase in Cash and Cash Equivalents	1,325	583
Cash and Cash Equivalents at Beginning of Period	509	1,096
Cash and Cash Equivalents at End of Period	$1,834	$1,679
SUPPLEMENTARY INFORMATION		

Cash Paid for Interest, Net of Capitalized Amounts	$56,599	$59,840
Net Cash Paid for Income Taxes	61,439	51,120
Noncash Acquisitions Under Capital Leases	679	9,521
Government Grants Included in Accounts Receivable at September 30,	1,539	-
Construction Expenditures Included in Current Liabilities at September 30,	12,534	12,561

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to CSPCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page 166.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Regulatory Activity

Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense. I&M plans to request an interim rate increase, subject to refund, for the portion of the $25 million that, among other things, excludes the depreciation rate changes and other regulatory amortizations. I&M plans to propose the interim rate increase be effective in January 2012. See "2011 Michigan Base Rate Case" section of Note 3.

Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense. See "2011 Indiana Base Rate Case" section of Note 3.

Cook Plant

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 $408 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. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1. 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 "Michigan 2009 and 2010 Power Supply Cost Recovery Reconciliations" section of Note 3 and "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, management expects the Nuclear Regulatory Commission and possibly Congress to review safety procedures and requirements for nuclear generating facilities. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. Management is unable to predict the impact of potential future regulation of nuclear facilities.

Litigation and Environmental Issues

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 166. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 232 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions of KWHs)			
Retail:				
Residential	1,657	1,714	4,662	4,689
Commercial	1,392	1,394	3,844	3,882
Industrial	1,920	1,851	5,635	5,547
Miscellaneous	14	16	52	52
Total Retail	4,983	4,975	14,193	14,170
Wholesale	3,024	2,510	7,529	6,210
Total KWHs	8,007	7,485	21,722	20,380

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in degree days)			
Actual - Heating (a)	15	2	2,635	2,279
Normal - Heating (b)	11	12	2,425	2,434
Actual - Cooling (c)	767	775	1,071	1,154
Normal - Cooling (b)	585	576	837	822

(a) Eastern 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.

Third Quarter of 2011 Compared to Third Quarter of 2010

Reconciliation of Third Quarter of 2010 to Third Quarter of 2011
Net Income
(in millions)

Third Quarter of 2010	$	62
Changes in Gross Margin:		
Retail Margins		(13)
FERC Municipals and Cooperatives		3
Off-system Sales		(1)
Transmission Revenues		(1)
Other Revenues		1
Total Change in Gross Margin		(11)
Changes in Expenses and Other:		
Other Operation and Maintenance		(5)
Depreciation and Amortization		1
Taxes Other Than Income Taxes		1
Other Income		(1)
Interest Expense		4
Total Change in Expenses and Other		-
Income Tax Expense		1
Third Quarter of 2011	$	52

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

- Retail Margins decreased $13 million primarily due to the following:
  - A $9 million decrease in capacity settlements under the Interconnection Agreement.
  - An $8 million decrease due to customer credits for a settlement relating to the Cook Plant Unit 1 (Unit 1) fire outage. This decrease was offset by a decrease in Other Operation and Maintenance expenses.

  These decreases were partially offset by:
  - A $4 million increase due to a Michigan rate settlement effective in December 2010.
- Margins from FERC Municipals and Cooperatives increased $3 million primarily due to higher sales resulting from favorable summer weather.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $5 million primarily due to the following:
  - A $9 million increase in transmission expense primarily due to the Transmission Agreement modification effective November 2010.
  - A $5 million increase in steam generation maintenance costs associated with scheduled outages.
  -

A $3 million increase in customer service costs associated with higher Demand Side Management (DSM) expenses. This increase is offset by an increase in Retail Margins above.

These increases were partially offset by:

- An $8 million decrease in steam power expenses relating to the Unit 1 fire outage. This decrease was offset by a decrease in Retail Margins.
- A $6 million decrease associated with the favorable resolution of a contingency.

- Interest Expense decreased $4 million primarily due to lower outstanding debt balances.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Reconciliation of Nine Months Ended September 30, 2010 to Nine Months Ended September 30, 2011
Net Income
(in millions)

Nine Months Ended September 30, 2010	$	122
Changes in Gross Margin:		
Retail Margins		(12)
FERC Municipals And Cooperatives		3
Off-system Sales		5
Transmission Revenues		(1)
Other Revenues		(2)
Total Change in Gross Margin		(7)
Changes in Expenses and Other:		
Other Operation and Maintenance		22
Depreciation and Amortization		1
Taxes Other Than Income Taxes		(2)
Other Income		(2)
Interest Expense		7
Total Change in Expenses and Other		26
Income Tax Expense		(12)
Nine Months Ended September 30, 2011	$	129

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

- Retail Margins decreased $12 million primarily due to the following:
  - A $27 million decrease in capacity settlements under the Interconnection Agreement.
  - A $14 million decrease due to customer credits for a settlement relating to the Unit 1 fire outage. This decrease was offset by a decrease in Other Operation and Maintenance expenses.

  These decreases were partially offset by:
  - A $30 million increase due to the Michigan rate settlement effective in December 2010 and recovery of costs through trackers.
- Margins from Off-system Sales increased $5 million primarily due to higher physical sales volumes, partially offset by lower trading and marketing margins.

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

- Other Operation and Maintenance expenses decreased $22 million primarily due to the following:
  - A $41 million decrease due to expenses related to the cost reduction initiatives recorded in the second and third quarters of 2010.
  -

- A $14 million decrease in steam power expenses relating to the Unit 1 fire outage. This decrease was offset by a decrease in Retail Margins.
- A $6 million decrease associated with the favorable resolution of a contingency.

These decreases were partially offset by:

- A $28 million increase in transmission expense primarily due to the Transmission Agreement modification effective November 2010.
- A $6 million increase in customer service costs associated with higher DSM expenses. This increase is offset by an increase in Retail Margins above.

- Interest Expense decreased $7 million primarily due to lower outstanding debt balances.
- Income Tax Expense increased $12 million primarily due to an increase in pretax book income, the regulatory accounting treatment of state income taxes and federal income tax adjustments related to prior year tax returns.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2010 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 232 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 232 for a discussion of market risk.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Three Months Ended 2011	Three Months Ended 2010	Nine Months Ended 2011	Nine Months Ended 2010
REVENUES				
Electric Generation, Transmission and Distribution	$494,860	$480,779	$1,371,349	$1,327,505
Sales to AEP Affiliates	83,417	93,984	229,187	245,674
Other Revenues - Affiliated	29,230	27,796	81,694	86,447
Other Revenues - Nonaffiliated	3,725	5,691	10,972	11,595
TOTAL REVENUES	611,232	608,250	1,693,202	1,671,221
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	135,927	134,721	359,311	356,160
Purchased Electricity for Resale	25,671	27,904	86,759	89,115
Purchased Electricity from AEP Affiliates	112,416	96,405	274,967	247,151
Other Operation	133,327	132,200	399,384	425,859
Maintenance	50,341	46,180	148,877	144,257
Depreciation and Amortization	33,214	34,130	100,564	101,932
Taxes Other Than Income Taxes	19,984	20,806	62,643	60,833
TOTAL EXPENSES	510,880	492,346	1,432,505	1,425,307
OPERATING INCOME	100,352	115,904	260,697	245,914
Other Income (Expense):				
Other Income	3,944	4,022	11,306	14,543
Interest Expense	(24,056)	(28,046)	(73,440)	(80,557)
INCOME BEFORE INCOME TAX EXPENSE	80,240	91,880	198,563	179,900
Income Tax Expense	28,538	29,580	70,048	57,940
NET INCOME	51,702	62,300	128,515	121,960
Preferred Stock Dividend Requirements	85	85	255	255
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$51,617	$62,215	$128,260	$121,705

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$56,584	$981,292	$656,608	$ (21,701)	$1,672,783
Common Stock Dividends			(78,250)		(78,250)
Preferred Stock Dividends			(255)		(255)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,594,278
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $77				(144)	(144)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $352				655	655
NET INCOME			121,960		121,960
TOTAL COMPREHENSIVE INCOME					122,471
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2010	$56,584	$981,292	$700,063	$ (21,190)	$1,716,749
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$56,584	$981,294	$677,360	$ (20,889)	$1,694,349
Common Stock Dividends			(56,250)		(56,250)
Preferred Stock Dividends			(255)		(255)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,637,844
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,063				(3,832)	(3,832)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $383				711	711
NET INCOME			128,515		128,515
TOTAL COMPREHENSIVE INCOME					125,394

TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$56,584	$981,294	$749,370	$ (24,010)	$1,763,238

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$1,154	$361
Advances to Affiliates	134,004	-
Accounts Receivable:		
Customers	75,435	76,193
Affiliated Companies	73,726	149,169
Accrued Unbilled Revenues	15,137	19,449
Miscellaneous	13,826	10,968
Allowance for Uncollectible Accounts	(2,099)	(1,692)
Total Accounts Receivable	176,025	254,087
Fuel	60,545	87,551
Materials and Supplies	164,861	178,331
Risk Management Assets	23,413	27,526
Accrued Tax Benefits	29,346	71,113
Deferred Cook Plant Fire Costs	61,261	45,752
Prepayments and Other Current Assets	33,831	33,713
TOTAL CURRENT ASSETS	684,440	698,434
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,812,564	3,774,262
Transmission	1,209,506	1,188,665
Distribution	1,464,455	1,411,095
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	729,393	719,708
Construction Work in Progress	366,185	301,534
Total Property, Plant and Equipment	7,582,103	7,395,264
Accumulated Depreciation, Depletion and Amortization	3,203,493	3,124,998
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,378,610	4,270,266
OTHER NONCURRENT ASSETS		
Regulatory Assets	540,210	556,254
Spent Nuclear Fuel and Decommissioning Trusts	1,512,704	1,515,227
Long-term Risk Management Assets	20,140	31,485
Deferred Charges and Other Noncurrent Assets	57,655	77,229
TOTAL OTHER NONCURRENT ASSETS	2,130,709	2,180,195
TOTAL ASSETS	$7,193,759	$7,148,895

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2011 and December 31, 2010
(dollars in thousands)
(Unaudited)

	2011	2010
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 42,769
Accounts Payable:		
General	110,631	121,665
Affiliated Companies	70,086	105,221
Long-term Debt Due Within One Year – Nonaffiliated		
(September 30, 2011 and December 31, 2010 amounts include $72,819 and		
$77,457, respectively, related to DCC Fuel)	155,307	154,457
Risk Management Liabilities	12,067	16,785
Customer Deposits	29,362	29,264
Accrued Taxes	99,447	62,637
Accrued Interest	22,602	27,444
Other Current Liabilities	143,836	140,710
TOTAL CURRENT LIABILITIES	643,338	700,952
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,830,426	1,849,769
Long-term Risk Management Liabilities	11,821	6,530
Deferred Income Taxes	845,031	760,105
Regulatory Liabilities and Deferred Investment Tax Credits	806,397	852,197
Asset Retirement Obligations	1,000,143	963,029
Deferred Credits and Other Noncurrent Liabilities	285,293	313,892
TOTAL NONCURRENT LIABILITIES	4,779,111	4,745,522
TOTAL LIABILITIES	5,422,449	5,446,474
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,072	8,072
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	981,294	981,294
Retained Earnings	749,370	677,360
Accumulated Other Comprehensive Income (Loss)	(24,010)	(20,889)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,763,238	1,694,349
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$ 7,193,759	$ 7,148,895

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 166.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$128,515	$121,960
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	100,564	101,932
Deferred Income Taxes	71,121	40,125
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	13,544	(12,323)
Allowance for Equity Funds Used During Construction	(11,790)	(11,945)
Mark-to-Market of Risk Management Contracts	9,014	(16,887)
Amortization of Nuclear Fuel	107,801	113,031
Pension Contributions to Qualified Plan Trust	(21,030)	(66,711)
Fuel Over/Under-Recovery, Net	(4,676)	(280)
Change in Other Noncurrent Assets	15,975	20,044
Change in Other Noncurrent Liabilities	45,633	63,409
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	78,062	4,814
Fuel, Materials and Supplies	40,476	(12,021)
Accounts Payable	(50,265)	(10,928)
Accrued Taxes, Net	74,510	72,156
Received Cook Plant Fire Costs	-	63,247
Other Current Assets	2,924	408
Other Current Liabilities	24,264	14,671
Net Cash Flows from Operating Activities	624,642	484,702
INVESTING ACTIVITIES		
Construction Expenditures	(224,749)	(224,488)