AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 26, 2012

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, 2012
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
1-3570	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) 1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000	72-0323455

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 the registrants have submitted electronically and posted on their corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were 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, 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

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric 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 25, 2012
American Electric Power Company, Inc.	485,249,096 ($6.50 par value)
Appalachian Power Company	13,499,500 (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, 2012

	Page Number
Glossary of Terms	i
Forward-Looking Information	iv
Part I. FINANCIAL INFORMATION	
Items 1, 2 and 3 - Financial Statements, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk:	
American Electric Power Company, Inc. and Subsidiary Companies:	
Management's Discussion and Analysis of Financial Condition and Results of Operations	1
Condensed Consolidated Financial Statements	30
Index of Condensed Notes to Condensed Consolidated Financial Statements	36
Appalachian Power Company and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	82
Condensed Consolidated Financial Statements	88
Index of Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	94
Indiana Michigan Power Company and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	96
Condensed Consolidated Financial Statements	103
Index of Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	109
Ohio Power Company Consolidated:	
Management's Narrative Discussion and Analysis of Results of Operations	111
Condensed Consolidated Financial Statements	119
Index of Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	125
Public Service Company of Oklahoma:	
Management's Narrative Discussion and Analysis of Results of Operations	127
Condensed Financial Statements	130
Index of Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	136
Southwestern Electric Power Company Consolidated:	
Management's Narrative Discussion and Analysis of Results of Operations	138
Condensed Consolidated Financial Statements	143
Index of Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	149
Index of Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	150
Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries	207

Controls and Procedures 214

Part II. OTHER INFORMATION			
Item 1.	Legal Proceedings		215
Item 1A.	Risk Factors		215
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds		217
Item 4.	Mine Safety Disclosures		217
Item 5.	Other Information		218
Item 6.	Exhibits:		218
		Exhibit 10	
		Exhibit 12	
		Exhibit 31(a)	
		Exhibit 31(b)	
		Exhibit 32(a)	
		Exhibit 32(b)	
		Exhibit 95	
		Exhibit 101.INS	
		Exhibit 101.SCH	
		Exhibit 101.CAL	
		Exhibit 101.DEF	
		Exhibit 101.LAB	
		Exhibit 101.PRE	
SIGNATURE			219

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian 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 utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP 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.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
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.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated 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 and consolidated variable interest entity of AEP.

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 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.
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	An agreement by and among APCo, 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.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
MWh	Megawatthour.
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	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
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, 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 for AEP and SWEPCo.
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.
SO2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III 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.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant under construction in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
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 2011 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 cost-related issues regarding I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage through warranty, insurance and the regulatory process.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission 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.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- 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, coal, natural gas and other energy-related commodities.
- 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.
- Volatility and changes in markets for electricity, coal, natural gas and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the transition to market and expected legal separation for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate or amend the Interconnection Agreement.
- 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.
- 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.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in the 2011 Annual Report and in Part II of this report.

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

EXECUTIVE OVERVIEW

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause and established a non-bypassable Distribution Investment Rider (DIR) effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the ESP approved a storm damage recovery mechanism which allowed OPCo to defer the majority of the incremental distribution operation and maintenance costs from 2012 storms.

Finally, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the standard service offer (SSO) load with delivery beginning six months after the receipt of ESP and corporate separation orders and extending through December 2014. The PUCO also ordered OPCo to conduct an energy-only auction for a total of 60% of the SSO load with delivery beginning June 2014 through May 2015. In addition, the PUCO ordered OPCo to conduct an energy-only auction for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. Starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load. In September 2012, OPCo and intervenors filed applications with the PUCO for rehearing. Rehearing of this order is pending at the PUCO.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers to the extent that the total incurred capacity costs do not exceed $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. Several parties, including OPCo, requested rehearing of the July 2012 PUCO order, which was upheld by the PUCO in October 2012. In the August 2012 PUCO order which adopted and modified the new ESP, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide $508 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. In August 2012, the Industrial Energy Users-Ohio (IEU) filed a claim before the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. OPCo and the PUCO filed motions to dismiss IEU's claim. If OPCo is ultimately not permitted to fully collect its deferred capacity costs and ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 2.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. As a result, in comparison to the third quarter of 2011 and the first nine months of 2011, we lost approximately $67 million and $165 million, respectively, of gross margin. This reduction in gross margin is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) Retail Stability Rider collections from Ohio retail distribution customers and (e) revenues from AEP Energy, our CRES provider and member of our Generation and Marketing segment. As of September 30, 2012, based upon an average annual load, approximately 42% of our Ohio load had switched to CRES providers and approximately 6% of our Ohio load had formally initiated the switching process to a CRES provider for a total of

48%. To enhance our competitive position in Ohio, AEP Energy targets retail customers, both within and outside of our retail service territory.

1

Proposed Corporate Separation and Termination of the Interconnection Agreement

In March 2012, OPCo filed an application with the PUCO for approval of the corporate separation of its generation assets including the transfer of generation assets to a nonregulated AEP subsidiary at net book value. In October 2012, the PUCO issued an order which approved the transfer of OPCo's generation assets at net book value to AEP Generation Resources, Inc. (AEPGenCo), a nonregulated affiliate in the Generation and Marketing segment. AEPGenCo will also assume the associated generation liabilities. Management intends to file an application with the FERC in the fourth quarter of 2012 related to corporate separation. Our results of operations related to generation in Ohio will be largely determined by our ability to sell power and capacity at a profit at rates determined by the prevailing market. If we are unable to sell power and capacity at a profit, it could reduce future net income and cash flows and impact financial condition.

In December 2010, each of the members of the Interconnection Agreement gave notice to AEPSC and each other of its decision to terminate the Interconnection Agreement effective as of December 31, 2013 or such other date as ordered by the FERC. Management intends to file an application with the FERC in the fourth quarter of 2012 to terminate the Interconnection Agreement. It is unknown whether the Interconnection Agreement 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. If any of the members of the Interconnection Agreement experience decreases in revenues or increases in costs as a result of the termination of the Interconnection Agreement 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.

Based on the interdependent nature of generation activities subject to the Interconnection Agreement, the AEP East companies' generation assets are evaluated for their accounting recoverability collectively as an asset group. We are monitoring the potential impact that the proposed corporate separation of OPCo's generation assets and the proposed termination of the Interconnection Agreement could have on the accounting evaluation of the recoverability of the net book values of OPCo's generation assets. The net book value of the OPCo units that we plan to retire included in the table below in the "Environmental Controls Impact on the Generating Fleet" section and our share of W. C. Beckjord Generating Station was $284 million as of September 30, 2012. These generating assets are being depreciated through May 2015.

Significantly Excessive Earnings Test

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. In May 2011, the Industrial Energy Users-Ohio and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended refunds of a portion of 2010 earnings. OPCo is required to file its 2011 SEET filing with the PUCO in 2012 on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo. See "Ohio Electric Security Plan Filing" section of Note 2.

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an

increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015.

In May 2012, the Indiana Office of Utility Consumer Counselor filed testimony that recommended an increase in base rates of $28 million, excluding reductions to certain riders, based upon a return on common equity of 9.2%. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders. Final hearings were held in June 2012. A decision from the IURC is expected in the fourth quarter of 2012. See "2011 Indiana Base Rate Case" section of Note 2.

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 scheduled to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. See "Turk Plant" section of Note 2.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operations and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. A decision from the PUCT is expected in the second quarter of 2013. See "2012 Texas Base Rate Case" section of Note 2.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings in equal monthly installment payments over the period January 2014 to May 2015 without interest. In the event Ormet, a large industrial customer in Ohio, does not pay the deferred billings, the PUCO permitted OPCo to recover the unpaid balance up to $20 million in future rates. To the extent unpaid deferred billings exceed $20 million, it will reduce future net income and cash flows.

Cook Plant

Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 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. 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 would reduce future net income and cash flows and impact financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 3.

Nuclear Regulatory Commission

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, the Nuclear Regulatory Commission (NRC) initiated a review of safety procedures and requirements for nuclear generating facilities. As a result, the NRC issued orders and guidance that increase procedures and testing requirements, require physical modifications to the plant and will increase future operating costs at the Cook Plant. We anticipate that future cumulative compliance costs will range from $40 million to $50 million. Approximately half of this estimate is expected to be capital. The remainder will be operating expenses that generally is expected to be incurred over the

plant’s life.

The NRC is also looking into the fuel used at eleven reactors, including the units at the Cook Plant. Their concern relates to fuel temperatures if abnormal conditions are experienced. We continue to monitor this issue and respond to the NRC's inquiry, as necessary. In addition to the review by the NRC, Congress could consider legislation increasing oversight of nuclear generating facilities. We are unable to predict the impact of potential future regulation of nuclear facilities.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant Units 1 and 2. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In Indiana, I&M requested recovery of certain project costs, including interest, through a rider effective January 2013. A hearing at the IURC is scheduled for January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of September 30, 2012, I&M has incurred $109 million related to the LCM Project, including AFUDC. Several intervenors filed testimony with various recommendations. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows. See "Cook Plant Life Cycle Management Project" section of Note 2.

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 3 – Rate Matters, Note 5 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis" in the 2011 Annual Report. Additionally, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

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. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. 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 and facilitate a comprehensive analysis of their impacts. The Senate is considering similar legislation. We believe that further analysis and better coordination of these 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 2011 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 reduce future net income and cash flows and impact financial condition.

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, 2012, the AEP System had a total generating capacity of 37,035 MWs, of which 23,900 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $6 billion to $7 billion between 2012 and 2020. These amounts include investments to convert 1,055 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, the units could be closed sooner than planned.

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 more stringent standards, (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 have given notice to the applicable RTOs of our intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
KPCo	Big Sandy Plant, Unit 1	278
OPCo	Conesville Plant, Unit 3	165
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528
Total		4,606

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

In September 2012, based upon an agreement in principle with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC to retire Units 3 and 4 of the Northeastern Station, a total of 930 MWs, in 2026 and 2016, respectively. See "Oklahoma Environmental Compliance Plan" and "Regional Haze" sections below.

Natural gas prices and pending environmental rules could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of certain coal-fired units. We are still evaluating our 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 based on changes in emission requirements and demand for power. To the extent existing

generation assets and the cost of new equipment and converted facilities are not recoverable under our accounting evaluations, it could materially reduce future net income and cash flows.

Environmental Compliance Applications

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of September 30, 2012, we have incurred $48 million, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows.

In July 2012, certain intervenors filed testimony which recommended cost caps ranging from $1.1 billion to $1.4 billion if the IURC approved the CPCN. In addition, the Indiana Office of Utility Consumer Counselor recommended the CPCN be denied until a more detailed project plan and cost estimates are filed with the IURC. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. A hearing is scheduled for December 2012.

Big Sandy Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system. KPCo is currently re-evaluating its options to meet the short and long-term energy needs of its customers at the most reasonable costs. As of September 30, 2012, KPCo has incurred $30 million related to the FGD project. Management intends to pursue recovery of all costs related to the FGD project. If KPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. Through September 30, 2012, SWEPCo has incurred $10 million related to this project, including AFUDC. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing at the APSC was held in October 2012 and a decision is pending from the APSC. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC which requested approval for (a) full cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at Northeastern Station Unit 3, (b) full cost recovery through 2026 of Northeastern Station Units 3 and 4 net book value (combined net book value of the two units is $235 million as of September 30, 2012), (c) full cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement with Calpine Oneta Power, effective in 2016, with cost recovery through a rider, including an earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

6

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the Cross-State Air Pollution Rule (CSAPR) trading programs to use those programs in place of source-specific BART for SO2 and NOx emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the United States Court of Appeals for the District of Columbia Circuit and its fate is uncertain given recent developments in the CSAPR litigation.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO2, NOx and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR 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. Arkansas and Louisiana are subject only to the seasonal NOx program in the rule. Texas is 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 were reduced significantly in the final rule. A supplemental rule includes Oklahoma in the seasonal NOx program. The supplemental rule was finalized in December 2011 with an increased NOx emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal

EPA and other respondents have filed petitions for rehearing. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance until the court responds to the rehearing petition in the main CSAPR appeal.

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. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In February 2012, the Federal EPA issued 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. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In July 2012, the Federal EPA issued a letter announcing that it will grant petitions for administrative reconsideration of certain issues related to the new source standards, including measurement issues and application of variability factors that may have an impact on the level of the standards. The letter also announced a three-month stay in the effective date of the new source standards. It is uncertain whether any of the information generated during the reconsideration process will affect the standards for existing sources.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the United States Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case. The Federal EPA granted petitions to reconsider certain issues related to the new source standards. Action by the court on these severed issues is being held in abeyance pending action on those petitions. The case is proceeding on the remaining issues and briefing is scheduled to be completed by April 2013.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed 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 proposed a 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. 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. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In April 2012, we reached an agreement in principle that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The parties are working toward finalizing a settlement agreement which is intended to allow PSO to meet its compliance obligations under the regional haze and HAPs rules.

CO2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources, and does not apply to units whose CO2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction, like our Turk Plant. The comment period closed in June 2012. New Source Performance Standards affect units that have not yet received permits, but complete the permitting process while the proposal is pending. The standards have been challenged in the United States Court of Appeals for the District of Columbia Circuit. We cannot predict the outcome of that litigation.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO2 emissions from new motor vehicles and its plan to phase in regulation of CO2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed and the court ordered the Federal EPA to respond in October 2012. The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

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 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. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash.

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 under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

9

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 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. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is not expected until July 2013. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

Global Warming

National public policy makers and regulators in the 11 states we serve have conflicting views on global warming. While comprehensive economy-wide regulation of CO2 emissions might be achieved through future 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.

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 of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements, including Michigan, Ohio, Texas and Virginia. 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 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 3.

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 reduce future net income and cash flows and impact financial condition.

For additional information on global warming, other environmental issues and the actions we are taking to address potential impacts, see Part I of the 2011 Form 10-K under the headings entitled "Business – General – Environmental and Other Matters" and "Management's Financial Discussion and Analysis."

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. 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. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

While our Utility Operations segment remains our primary business segment, the advancement of an area of our business prompted us to identify a new reportable segment. Starting in the fourth quarter of 2011, we established our new Transmission Operations segment as described below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

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

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The table below presents our consolidated Income Before Extraordinary Item by segment for the three and nine months ended September 30, 2012 and 2011. We reclassified prior year amounts to conform to the current year's presentation.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Utility Operations	$471	$633	$1,220	$1,357
Transmission Operations	14	9	31	19
AEP River Operations	(1)	17	11	23
Generation and Marketing	10	8	4	20
All Other (a)	(6)	(10)	(25)	(54)
Income Before Extraordinary Item	$488	$657	$1,241	$1,365

(a) While not considered a reportable 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 were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ended in the fourth quarter of 2011.

AEP CONSOLIDATED

Third Quarter of 2012 Compared to Third Quarter of 2011

Income Before Extraordinary Item decreased from $657 million in 2011 to $488 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in the third quarter 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
- The loss of retail customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- A decrease in AEP River Operations' earnings due to the impact of the 2012 drought.

These decreases were partially offset by:

- The third quarter 2011 plant impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.

Average basic shares outstanding increased from 482 million in 2011 to 485 million in 2012. Actual shares outstanding were 485 million as of September 30, 2012.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Income Before Extraordinary Item decreased from $1,365 million in 2011 to $1,241 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in the third quarter 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
- The loss of retail customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- The increase in depreciation expenses as a result of shortened depreciable lives for certain OPCo generating plants.

These decreases were partially offset by:

- The third quarter 2011 plant impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
- The first quarter 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.
- A second quarter 2012 partial reversal of a 2011 deferred fuel adjustment based on an April 2012 PUCO order related to the 2009 FAC audit.
- A first quarter 2011 settlement of litigation with BOA and Enron.

Average basic shares outstanding increased from 482 million in 2011 to 484 million in 2012. Actual shares outstanding were 485 million as of September 30, 2012.

Our results of operations are discussed below by operating segment.

12

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 electricity. We reclassified prior year amounts to conform to the current year's presentation.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Revenues	$3,839	$4,074	$10,482	$10,986
Fuel and Purchased Electricity	1,401	1,609	3,766	4,136
Gross Margin	2,438	2,465	6,716	6,850
Other Operation and Maintenance	858	884	2,383	2,586
Asset Impairments and Other Related Charges	13	90	13	90
Depreciation and Amortization	458	435	1,318	1,226
Taxes Other Than Income Taxes	219	210	632	618
Operating Income	890	846	2,370	2,330
Interest and Investment Income	2	17	5	21
Carrying Costs Income	11	291	42	323
Allowance for Equity Funds Used During Construction	19	23	59	65
Interest Expense	(221)	(222)	(662)	(681)
Income Before Income Tax Expense and Equity Earnings	701	955	1,814	2,058
Income Tax Expense	231	324	596	704
Equity Earnings of Unconsolidated Subsidiaries	1	2	2	3
Income Before Extraordinary Item	$471	$633	$1,220	$1,357

Summary of KWh Energy Sales for Utility Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions of KWhs)			
Retail:				
Residential	17,664	18,238	45,617	48,690
Commercial	14,091	14,274	38,444	38,833
Industrial	14,729	15,206	44,798	44,688
Miscellaneous	824	854	2,325	2,354
Total Retail (a)	47,308	48,572	131,184	134,565
Wholesale	12,876	13,164	30,409	32,532
Total KWhs	60,184	61,736	161,593	167,097

(a) Represents energy delivered to distribution customers.

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,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in degree days)			
Eastern Region				
Actual - Heating (a)	9	6	1,388	1,995
Normal - Heating (b)	7	7	1,923	1,914
Actual - Cooling (c)	816	838	1,245	1,209
Normal - Cooling (b)	709	700	1,012	999
Western Region				
Actual - Heating (a)	-	-	348	702
Normal - Heating (b)	1	1	602	601
Actual - Cooling (d)	1,525	1,669	2,619	2,813
Normal - Cooling (b)	1,367	1,359	2,201	2,179

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

Third Quarter of 2012 Compared to Third Quarter of 2011

Reconciliation of Third Quarter of 2011 to Third Quarter of 2012
Income from Utility Operations before Extraordinary Item
(in millions)

Third Quarter of 2011	$	633
Changes in Gross Margin:		
Retail Margins		(38)
Off-system Sales		(20)
Transmission Revenues		20
Other Revenues		11
Total Change in Gross Margin		(27)
Changes in Expenses and Other:		
Other Operation and Maintenance		26
Asset Impairments and Other Related Charges		77
Depreciation and Amortization		(23)
Taxes Other Than Income Taxes		(9)
Interest and Investment Income		(15)
Carrying Costs Income		(280)
Allowance for Equity Funds Used During Construction		(4)
Interest Expense		1
Equity Earnings of Unconsolidated Subsidiaries		(1)
Total Change in Expenses and Other		(228)
Income Tax Expense		93
Third Quarter of 2012	$	471

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 electricity were as follows:

- Retail Margins decreased $38 million primarily due to the following:
  - An $80 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $29 million decrease in weather-related usage primarily due to a 3% and 9% decrease in cooling degree days in our eastern and western service territories, respectively.
  - A $10 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the third quarter 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

  These decreases were partially offset by:
  - Successful rate proceedings in our service territories which include:
    - A $44 million rate increase for OPCo.

- A $24 million rate increase for APCo.

  For the rate increases described above, $36 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.
- A $13 million decrease in recoverable PJM expenses in Ohio.

- Margins from Off-system Sales decreased $20 million primarily due to lower market prices, reduced physical sales volumes and lower trading and marketing margins.
- Transmission Revenues increased $20 million primarily due to net increases in ERCOT and increased transmission revenues from Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets a portion of the lost revenues included in Retail Margins above.

- Other Revenues increased $11 million primarily due to an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase is partially offset by an increase in Depreciation and Amortization expense.

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

- Other Operation and Maintenance expenses decreased $26 million primarily due to the following:
  - A $40 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $9 million decrease due to the third quarter 2011 write-off of Ohio allocated Front-End Engineering and Design (FEED) study costs related to the Mountaineer Carbon Capture Project.
  - A $4 million decrease in employee-related expenses.

  These decreases were partially offset by:
  - A $16 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $12 million increase in storm expenses primarily due to the 2012 summer storms.
- Asset Impairments and Other Related Charges decreased $77 million primarily due to the third quarter 2011 plant impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
- Depreciation and Amortization expenses increased $23 million primarily due to the following:
  - A $20 million increase due to TCC’s issuance of securitization bonds in March 2012. The increase in TCC’s securitization related amortizations are offset within Gross Margin.
  - A $17 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011.
  - A $15 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.
  - A $4 million increase in amortization as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - A $4 million increase in amortization of the Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $21 million decrease due to OPCo's 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 partially offset by amounts recognized in Carrying Costs Income as discussed below.
  - A $10 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $9 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate

proceeding.

- Interest and Investment Income decreased $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 decreased $280 million primarily due to the following:
  - A $261 million decrease in carrying costs income due to the recognition in the third quarter 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
  - An $11 million decrease primarily 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.
- Income Tax Expense decreased $93 million primarily due to a decrease in pre-tax book income.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Reconciliation of Nine Months Ended September 30, 2011 to Nine Months Ended September 30, 2012
Income from Utility Operations before Extraordinary Item
(in millions)

Nine Months Ended September 30, 2011	$	1,357
Changes in Gross Margin:		
Retail Margins		(153)
Off-system Sales		(19)
Transmission Revenues		55
Other Revenues		(17)
Total Change in Gross Margin		(134)
Changes in Expenses and Other:		
Other Operation and Maintenance		203
Asset Impairments and Other Related Charges		77
Depreciation and Amortization		(92)
Taxes Other Than Income Taxes		(14)
Interest and Investment Income		(16)
Carrying Costs Income		(281)
Allowance for Equity Funds Used During Construction		(6)
Interest Expense		19
Equity Earnings of Unconsolidated Subsidiaries		(1)
Total Change in Expenses and Other		(111)
Income Tax Expense		108
Nine Months Ended September 30, 2012	$	1,220

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 electricity were as follows:

- Retail Margins decreased $153 million primarily due to the following:
  - A $204 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $119 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 30% and 50%, respectively, in heating degree days and a 7% decrease in cooling degree days in our western region.
  - An $81 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the third quarter 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

These decreases were partially offset by:

- Successful rate proceedings in our service territories which include:
  - A $94 million rate increase for OPCo.
  - A $56 million rate increase for APCo.
  - A $16 million rate increase for I&M.
  - An $11 million rate increase for PSO.

  For the rate increases described above, $108 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.
- A $35 million increase due to OPCo's second quarter 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
- A $30 million decrease in recoverable PJM expenses in Ohio.

  - A $9 million deferral of APCo's additional wind purchase recovery costs as a result of the June 2012 Virginia SCC fuel factor order.
- Margins from Off-system Sales decreased $19 million primarily due to lower market prices, reduced physical sales volumes and lower trading and marketing margins, partially offset by higher PJM capacity revenues.
- Transmission Revenues increased $55 million primarily due to net increases in ERCOT and increased transmission revenues from Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets a portion of the lost revenues included in Retail Margins above.
- Other Revenues decreased $17 million primarily due to a decrease in gains on miscellaneous sales, partially offset by an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase in revenues from securitization bonds is partially offset by an increase in Depreciation and Amortization expense.

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

- Other Operation and Maintenance expenses decreased $203 million primarily due to the following:
  - A $115 million decrease in plant outage and other plant operating and maintenance expenses.
  - An $87 million decrease in employee-related expenses.
  - A $41 million decrease 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 $30 million net decrease related to the reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO’s February 2012 rejection of the Ohio modified stipulation and the PUCO's August 2012 approval of the June 2012-May 2015 ESP.
  - A $14 million decrease due to APCo's deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC.
  - A $9 million decrease due to the third quarter 2011 write-off of Ohio allocated FEED study costs related to the Mountaineer Carbon Capture Project.

  These decreases were partially offset by:
  - A $33 million increase due to the first quarter 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC in 2011.
  - A $24 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $14 million increase due to expenses related to the 2012 sustainable cost reductions.
  - An $11 million gain from the sale of land in January 2011.
- Asset Impairments and Other Related Charges decreased $77 million primarily due to the third quarter 2011 plant impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
- Depreciation and Amortization expenses increased $92 million primarily due to the following:
  - A $49 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011.
  - A $42 million increase due to TCC’s issuance of securitization bonds in March 2012. The increase in TCC’s securitization related amortizations are offset within Gross Margin.
  - A $35 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012

(Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.

- A $10 million increase in amortization as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012. This increase in amortization is offset within Gross Margin.
- A $9 million increase in amortization of OPCo's Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
- Overall higher depreciable property balances.

These increases were partially offset by:

  - A $29 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $21 million decrease due to OPCo's 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.
  - A $13 million decrease in OPCo's depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.
  - A $9 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate proceeding.
- Taxes Other Than Income Taxes increased $14 million primarily due to increased property taxes as a result of increased capital investments.
- Interest and Investment Income decreased $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 decreased $281 million primarily due to the following:
  - A $261 million decrease in carrying costs income due to the recognition in the third quarter 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005.
  - An $11 million decrease 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.
  - A $5 million reduction in debt carrying charges associated with the 2008 coal contract settlement for the period January 2009 through March 2012 as ordered by the PUCO in April 2012 related to the 2009 FAC audit.

  These decreases were offset by:
  - An $8 million increase due to the recording of debt carrying costs prior to TCC’s issuance of securitization bonds in March 2012.
- Interest Expense decreased $19 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense decreased $108 million primarily due to a decrease in pre-tax book income and audit settlements for previous years.

TRANSMISSION OPERATIONS

Third Quarter of 2012 Compared to Third Quarter of 2011

Net Income from our Transmission Operations segment increased from $9 million in 2011 to $14 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Net Income from our Transmission Operations segment increased from $19 million in 2011 to $31 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

Third Quarter of 2012 Compared to Third Quarter of 2011

Net Income from our AEP River Operations segment decreased from income of $17 million in 2011 to a loss of $1 million in 2012 primarily due to reduced volumes and rates as a result of the 2012 drought which impacted both river conditions and grain harvests. In addition, as a result of Hurricane Isaac, shipping in the Gulf Region ceased for a period of time in late August and early September 2012.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Net Income from our AEP River Operations segment decreased from $23 million in 2011 to $11 million in 2012 primarily due to reduced volumes and rates as a result of the 2012 drought which impacted both river conditions and grain harvests. In addition, as a result of Hurricane Isaac, shipping in the Gulf Region ceased for a period of time in late August and early September 2012.

GENERATION AND MARKETING

Third Quarter of 2012 Compared to Third Quarter of 2011

Net Income from our Generation and Marketing segment increased from $8 million in 2011 to $10 million in 2012 primarily due to higher trading margins and higher retail margins in PJM partially offset by lower gross margins at the Oklaunion Plant and the expiration of wind-related production tax credits in 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Net Income from our Generation and Marketing segment decreased from $20 million in 2011 to $4 million in 2012 primarily due to the expiration of wind-related production tax credits in 2011 and lower gross margins at the Oklaunion Plant, partially offset by higher retail margins in PJM and higher trading margins.

ALL OTHER

Third Quarter of 2012 Compared to Third Quarter of 2011

Net Income from All Other increased from a loss of $10 million in 2011 to a loss of $6 million in 2012 primarily due to a reduction in interest expense partially offset by a 2011 gain on sale of assets.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Net Income from All Other increased from a loss of $54 million in 2011 to a loss of $25 million in 2012 primarily due to a loss incurred in the first quarter of 2011 related to the settlement of litigation with BOA and Enron.

AEP SYSTEM INCOME TAXES

Third Quarter of 2012 Compared to Third Quarter of 2011

Income Tax Expense decreased $93 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Income Tax Expense decreased $166 million primarily due to a decrease in pretax book income and the 2011 unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2012		December 31, 2011	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 17,227	51.0 %	$ 16,516	50.3 %
Short-term Debt	1,216	3.6	1,650	5.0
Total Debt	18,443	54.6	18,166	55.3
AEP Common Equity	15,306	45.4	14,664	44.7
Noncontrolling Interests	-	-	1	-
Total Debt and Equity Capitalization	$ 33,749	100.0 %	$ 32,831	100.0 %

Our ratio of debt-to-total capital decreased from 55.3% as of December 31, 2011 to 54.6% as of September 30, 2012. Long-term debt outstanding increased primarily due to the March 2012 issuance of $800 million of securitization bonds.

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. As of September 30, 2012, 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-and-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of September 30, 2012, our available liquidity was approximately $3 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		443	
Total Liquidity Sources		3,693	
Less:	AEP Commercial Paper Outstanding	520	
	Letters of Credit Issued	132	

Net Available Liquidity	$	3,041

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.

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 2012 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2012 was 0.45%.

Securitized Accounts Receivable

In June 2012, we renewed our receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

Securitization of Regulatory Assets

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework to securitize certain deferred Expanded Net Energy Charge (ENEC) balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. A hearing is scheduled in December 2012.

In August 2012, OPCo filed an application with the PUCO requesting securitization of the Deferred Asset Recovery Rider (DARR) balance. As of September 30, 2012, OPCo's DARR balance was $296 million, including $139 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018 by a non-bypassable rider.

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 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. As of September 30, 2012, this contractually-defined percentage was 49.5%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of September 30, 2012, 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 any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of September 30, 2012, 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 2012. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

We do not believe restrictions related to our various financing arrangements 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,	
	2012	2011
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 221	$ 294
Net Cash Flows from Operating Activities	2,912	3,338
Net Cash Flows Used for Investing Activities	(2,281)	(1,967)
Net Cash Flows Used for Financing Activities	(409)	(1,119)
Net Increase in Cash and Cash Equivalents	222	252
Cash and Cash Equivalents at End of Period	$ 443	$ 546

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,	
	2012	2011
	(in millions)	
Net Income	$ 1,241	$ 1,638
Depreciation and Amortization	1,353	1,258
Other	318	442
Net Cash Flows from Operating Activities	$ 2,912	$ 3,338

Net Cash Flows from Operating Activities were $2.9 billion in 2012 consisting primarily of Net Income of $1.2 billion and $1.4 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. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Cash was used to pay real and personal property taxes and to reduce accounts payable. 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 and an increase in tax versus book temporary differences from operations. We also contributed $100 million to our qualified pension trust.

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.

Investing Activities

	Nine Months Ended September 30,	
	2012	2011
	(in millions)	
Construction Expenditures	$ (2,108)	$ (1,849)
Acquisitions of Nuclear Fuel	(13)	(104)
Acquisitions of Assets/Businesses	(89)	(10)
Acquisition of Cushion Gas from BOA	-	(214)
Proceeds from Sales of Assets	13	116
Other	(84)	94
Net Cash Flows Used for Investing Activities	$ (2,281)	$ (1,967)

Net Cash Flows Used for Investing Activities were $2.3 billion in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for $70 million.

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.

Financing Activities

	Nine Months Ended September 30,	
	2012	2011
	(in millions)	
Issuance of Common Stock, Net	$ 64	$ 70
Issuance of Debt, Net	262	(469)
Dividends Paid on Common Stock	(687)	(668)
Other	(48)	(52)
Net Cash Flows Used for Financing Activities	$ (409)	$ (1,119)

Net Cash Flows Used for Financing Activities in 2012 were $409 million. Our net debt issuances were $262 million. The net issuances included issuances of $800 million of securitization bonds, $550 million of senior unsecured notes,

$197 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $513 million of senior unsecured and other debt notes, $220 million of pollution control bonds, $171 million of securitization bonds and a decrease in short-term borrowing of $434 million. We paid common stock dividends of $687 million. See Note 10 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

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.

In October 2012, I&M retired $29 million of Notes Payable related to DCC Fuel.

In October 2012, AEP Transmission Company, LLC completed a $350 million debt offering. This debt offering resulted in the October 2012 issuance of $250 million of Senior Notes in three tranches. The tranches are $104 million at 3.3% due in 2022, $85 million at 4% due in 2032 and $61 million at 4.73% due in 2042. The remaining $100 million will be issued in two tranches in December 2012 and March 2013.

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 guidelines restrict 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, 2012	December 31, 2011
	(in millions)	
Rockport Plant Unit 2 Future Minimum Lease Payments	$ 1,552	$ 1,626
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 2011 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2011 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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Financial Discussion and Analysis” in the 2011 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.

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future

changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future 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 as we occasionally 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 conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail 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.

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 and Finance groups in accordance with our established risk management policies as 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 Chief Operating Officer, 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, 2011:

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2012

	Utility Operations	Generation and Marketing	Total
		(in millions)	
Total MTM Risk Management Contract Net Assets as of December 31, 2011	$ 59	$ 132	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	2	(2)	-
Fair Value of New Contracts at Inception When Entered During the Period (a)	5	16	21
Acquisition of Supply Contracts (b)	-	(25)	(25)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	4	2	6
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	4	-	4
Total MTM Risk Management Contract Net Assets as of September 30, 2012	$ 74	$ 123	197
Commodity Cash Flow Hedge Contracts			1
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(39)
Fair Value Hedge Contracts			2
Collateral Deposits			30
Total MTM Derivative Contract Net Assets as of September 30, 2012			$ 191

(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) Reflects liabilities associated with supply contracts from the BlueStar acquisition in March 2012.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d) Relates to the net gains (losses) of those contracts that are not reflected on the condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 7 – Derivatives and Hedging and Note 8 – 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, 2012, our credit exposure net of collateral to sub investment grade counterparties was approximately 6%, 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, 2012, 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	$ 651	$ -	$ 651	2	$ 268
Split Rating	-	-	-	-	-
Noninvestment Grade	2	2	-	-	-
No External Ratings:					
Internal Investment Grade	109	-	109	2	27
Internal Noninvestment Grade	60	10	50	1	36
Total as of September 30, 2012	$ 822	$ 12	$ 810	5	$ 331
Total as of December 31, 2011	$ 960	$ 19	$ 941	5	$ 348

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, 2012, 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, 2012				Twelve Months Ended December 31, 2011			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 2	$ -	$ -

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, 2012 and December 31, 2011, the estimated EaR on our debt portfolio for the following twelve months was $32 million and $29 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2012 and 2011
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REVENUES				
Utility Operations	$3,814	$4,044	$10,412	$10,901
Other Revenues	342	289	920	771
TOTAL REVENUES	4,156	4,333	11,332	11,672
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,180	1,371	3,137	3,407
Purchased Electricity for Resale	327	294	855	856
Other Operation	775	747	2,150	2,130
Maintenance	255	283	769	864
Asset Impairments and Other Related Charges	13	90	13	90
Depreciation and Amortization	470	445	1,353	1,258
Taxes Other Than Income Taxes	224	213	648	628
TOTAL EXPENSES	3,244	3,443	8,925	9,233
OPERATING INCOME	912	890	2,407	2,439
Other Income (Expense):				
Interest and Investment Income	2	19	6	24
Carrying Costs Income	11	291	42	323
Allowance for Equity Funds Used During Construction	23	26	70	69
Interest Expense	(233)	(242)	(697)	(723)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	715	984	1,828	2,132
Income Tax Expense	241	334	620	786
Equity Earnings of Unconsolidated Subsidiaries	14	7	33	19
INCOME BEFORE EXTRAORDINARY ITEM	488	657	1,241	1,365
EXTRAORDINARY ITEM, NET OF TAX	-	273	-	273
NET INCOME	488	930	1,241	1,638
Net Income Attributable to Noncontrolling Interests	1	1	3	3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	487	929	1,238	1,635

Preferred Stock Dividend Requirements of Subsidiaries	-	1	-	2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$487	$928	$1,238	$1,633
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,979,543	482,498,734	484,437,875	481,862,128
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Extraordinary Item	$1.00	$1.35	$2.55	$2.82
Extraordinary Item, Net of Tax	-	0.57	-	0.57
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.00	$1.92	$2.55	$3.39
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	485,362,858	482,796,945	484,826,123	482,126,964
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Extraordinary Item	$1.00	$1.35	$2.55	$2.82
Extraordinary Item, Net of Tax	-	0.57	-	0.57
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.00	$1.92	$2.55	$3.39
CASH DIVIDENDS DECLARED PER SHARE	$0.47	$0.46	$1.41	$1.38

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 36.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2012 and 2011
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Net Income	$488	$930	$1,241	$1,638
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $7 and $11 for the Three Months Ended				
September 30, 2012 and 2011, Respectively, and $4 and $8 for the Nine				
Months Ended September 30, 2012 and 2011, Respectively	13	(20)	(8)	(14)
Securities Available for Sale, Net of Tax of $- and $2 for the Three Months				
Ended September 30, 2012 and 2011, Respectively, and $1 and $2 for the				
Nine Months Ended September 30, 2012 and 2011, Respectively	1	(4)	2	(3)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $4				
and $3 for the Three Months Ended September 30, 2012 and 2011,				
Respectively, and $12 and $9 for the Nine Months Ended September 30,				
2012 and 2011, Respectively	7	6	22	18
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	21	(18)	16	1
TOTAL COMPREHENSIVE INCOME	509	912	1,257	1,639
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP				
SHAREHOLDERS	508	911	1,254	1,636
Preferred Stock Dividend Requirements of Subsidiaries	-	1	-	2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP				
COMMON SHAREHOLDERS	$508	$910	$1,254	$1,634

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 36.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2012 and 2011
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock		Paid-in	Retained	Accumulated Other Comprehensive Income	Noncontrolling	
	Shares	Amount	Capital	Earnings	(Loss)	Interests	Total
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
Net Income				1,635		3	1,638
Other Comprehensive Income					1		1
TOTAL EQUITY – SEPTEMBER 30, 2011	503	$ 3,271	$ 5,952	$ 5,810	$ (380)	$ -	$ 14,653
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665
Issuance of Common Stock	2	12	52				64
Common Stock Dividends				(684)		(3)	(687)
Other Changes in Equity			8			(1)	7
Subtotal – Equity							14,049
Net Income				1,238		3	1,241
Other Comprehensive Income					16		16
TOTAL EQUITY – SEPTEMBER 30, 2012	506	$ 3,286	$ 6,030	$ 6,444	$ (454)	$ -	$ 15,306

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 36.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2012 and December 31, 2011
(in millions)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 443	$ 221
Other Temporary Investments (September 30, 2012 and December 31, 2011 Amounts Include $265 and $281, Respectively, Related to Transition Funding and EIS)	278	294
Accounts Receivable:		
Customers	684	690
Accrued Unbilled Revenues	210	106
Pledged Accounts Receivable – AEP Credit	909	920
Miscellaneous	92	150
Allowance for Uncollectible Accounts	(40)	(32)
Total Accounts Receivable	1,855	1,834
Fuel	800	657
Materials and Supplies	662	635
Risk Management Assets	175	193
Accrued Tax Benefits	49	51
Regulatory Asset for Under-Recovered Fuel Costs	103	65
Margin Deposits	74	67
Prepayments and Other Current Assets	209	165
TOTAL CURRENT ASSETS	4,648	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,463	24,938
Transmission	9,503	9,048
Distribution	15,359	14,783
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,943	3,780
Construction Work in Progress	3,191	3,121
Total Property, Plant and Equipment	57,459	55,670
Accumulated Depreciation and Amortization	19,326	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	38,133	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,306	6,026
Securitized Transition Assets	2,179	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,700	1,592
Goodwill	90	76
Long-term Risk Management Assets	390	403

Deferred Charges and Other Noncurrent Assets		1,397		1,346
TOTAL OTHER NONCURRENT ASSETS		11,062		11,070
TOTAL ASSETS	$	53,843	$	52,223

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 36.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2012 and December 31, 2011
(dollars in millions)
(Unaudited)

	2012	2011
CURRENT LIABILITIES		
Accounts Payable	$ 988	$ 1,095
Short-term Debt:		
Securitized Debt for Receivable - AEP Credit	696	666
Other Short-term Debt	520	984
Total Short-term Debt	1,216	1,650
Long-term Debt Due Within One Year (September 30, 2012 and December 31, 2011 Amounts Include $375 and $293, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	2,272	1,433
Risk Management Liabilities	150	150
Customer Deposits	295	289
Accrued Taxes	512	717
Accrued Interest	249	279
Regulatory Liability for Over-Recovered Fuel Costs	76	8
Other Current Liabilities	1,037	990
TOTAL CURRENT LIABILITIES	6,795	6,611
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2012 and December 31, 2011 Amounts Include $2,295 and $1,674, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	14,955	15,083
Long-term Risk Management Liabilities	224	195
Deferred Income Taxes	8,905	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,589	3,195
Asset Retirement Obligations	1,535	1,472
Employee Benefits and Pension Obligations	1,611	1,801
Deferred Credits and Other Noncurrent Liabilities	923	974
TOTAL NONCURRENT LIABILITIES	31,742	30,947
TOTAL LIABILITIES	38,537	37,558
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		
	2012	2011
Shares Authorized	600,000,000	600,000,000

Shares Issued	505,552,303	503,759,460		
(20,336,592 Shares were Held in Treasury as of September 30, 2012 and December 31, 2011)			3,286	3,274
Paid-in Capital			6,030	5,970
Retained Earnings			6,444	5,890
Accumulated Other Comprehensive Income (Loss)			(454)	(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			15,306	14,664
Noncontrolling Interests			-	1
TOTAL EQUITY			15,306	14,665
TOTAL LIABILITIES AND EQUITY			$ 53,843	$ 52,223

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 36.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012 and 2011
(in millions)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 1,241	$ 1,638
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,353	1,258
Deferred Income Taxes	592	764
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	13	90
Carrying Costs Income	(42)	(323)
Allowance for Equity Funds Used During Construction	(70)	(69)
Mark-to-Market of Risk Management Contracts	70	84
Amortization of Nuclear Fuel	100	108
Pension Contributions to Qualified Plan Trust	(100)	(150)
Property Taxes	181	173
Fuel Over/Under-Recovery, Net	133	(94)
Change in Other Noncurrent Assets	(195)	(32)
Change in Other Noncurrent Liabilities	119	225
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4)	51
Fuel, Materials and Supplies	(169)	275
Accounts Payable	(135)	(66)
Accrued Taxes, Net	(130)	(42)
Accrued Interest	(32)	(46)
Other Current Assets	(28)	13
Other Current Liabilities	15	16
Net Cash Flows from Operating Activities	2,912	3,338
INVESTING ACTIVITIES		
Construction Expenditures	(2,108)	(1,849)
Change in Other Temporary Investments, Net	19	62
Purchases of Investment Securities	(745)	(1,024)
Sales of Investment Securities	699	1,094
Acquisitions of Nuclear Fuel	(13)	(104)
Acquisitions of Assets/Businesses	(89)	(10)
Acquisition of Cushion Gas from BOA	-	(214)
Proceeds from Sales of Assets	13	116
Other Investing Activities	(57)	(38)
Net Cash Flows Used for Investing Activities	(2,281)	(1,967)

FINANCING ACTIVITIES				
Issuance of Common Stock, Net		64		70
Issuance of Long-term Debt		1,600		1,118
Commercial Paper and Credit Facility Borrowings		21		462
Change in Short-term Debt, Net		(417)		290
Retirement of Long-term Debt		(904)		(1,520)
Commercial Paper and Credit Facility Repayments		(38)		(819)
Principal Payments for Capital Lease Obligations		(53)		(53)
Dividends Paid on Common Stock		(687)		(668)
Dividends Paid on Cumulative Preferred Stock		-		(2)
Other Financing Activities		5		3
Net Cash Flows Used for Financing Activities		(409)		(1,119)
Net Increase in Cash and Cash Equivalents		222		252
Cash and Cash Equivalents at Beginning of Period		221		294
Cash and Cash Equivalents at End of Period	$	443	$	546
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	698	$	716
Net Cash Paid (Received) for Income Taxes		(44)		(119)
Noncash Acquisitions Under Capital Leases		46		39
Construction Expenditures Included in Current Liabilities as of September 30,		325		304
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,		43		-
Noncash Assumption of Liabilities Related to Acquisitions		56		-
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement		-		27

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 36.

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

1. Significant Accounting Matters
2. Rate Matters
3. Commitments, Guarantees and Contingencies
4. Acquisition and Impairments
5. Benefit Plans
6. Business Segments
7. Derivatives and Hedging
8. Fair Value Measurements
9. Income Taxes
10. Financing Activities
11. Sustainable Cost Reductions

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, 2012 is not necessarily indicative of results that may be expected for the year ending December 31, 2012. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2011 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 28, 2012.

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, variable interests held by related parties 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, 2012 and 2011 were $35 million and $33 million, respectively, and for the nine months ended September 30, 2012 and 2011 were $126 million and $97 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our condensed balance sheets.

37

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the three months ended September 30, 2012 and 2011 were $16 million and $16 million, respectively, and for the nine months ended September 30, 2012 and 2011 were $31 million and $46 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, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V 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. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended September 30, 2012 and 2011 were $23 million and $6 million, respectively, and for the nine months ended September 30, 2012 and 2011 were $82 million and $49 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 respective lease terms, which do not exceed 54 months. 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 10.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. 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 $2.3 billion and $1.7 billion as of September 30, 2012 and December 31, 2011, respectively, and are included in current and long-term debt on the condensed balance sheets. Transition Funding has securitized transition assets of $2.2 billion and $1.6 billion as of September 30, 2012 and December 31, 2011, 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 assets 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, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 71	$ 155	$ 137	$ 895	$ 222
Net Property, Plant and Equipment	175	208	-	-	-
Other Noncurrent Assets	56	113	5	1	2,231 (a)
Total Assets	$ 302	$ 476	$ 142	$ 896	$ 2,453
LIABILITIES AND EQUITY					
Current Liabilities	$ 45	$ 128	$ 50	$ 850	$ 293
Noncurrent Liabilities	257	348	71	1	2,142
Equity	-	-	21	45	18
Total Liabilities and Equity	$ 302	$ 476	$ 142	$ 896	$ 2,453

(a) Includes an intercompany item eliminated in consolidation of $90 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2011
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 48	$ 118	$ 121	$ 910	$ 220
Net Property, Plant and Equipment	154	188	-	-	-
Other Noncurrent Assets	42	118	6	1	1,580
Total Assets	$ 244	$ 424	$ 127	$ 911	$ 1,800

LIABILITIES AND EQUITY					
Current Liabilities	$ 68	$ 103	$ 40	$ 864	$ 229
Noncurrent Liabilities	176	321	71	1	1,557
Equity	-	-	16	46	14
Total Liabilities and Equity	$ 244	$ 424	$ 127	$ 911	$ 1,800

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 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, 2012 and 2011 were $20 million and $18 million, respectively and for the nine months ended September 30, 2012 and 2011 were $54 million and $47 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, 2012		December 31, 2011	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$8	$8	$8	$8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	53	-	52
Total Investment in DHLC	$9	$62	$9	$61

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). 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. The entities recover costs through regulated rates.

Based upon an analysis of the potential need for PATH, the PJM board cancelled PATH in August 2012. In September 2012, we and FirstEnergy submitted an abandonment filing with the FERC seeking authority to recover prudently-incurred costs associated with PATH, including a return, over a sixty-month amortization period.

Our investment in PATH-WV was:

	September 30, 2012		December 31, 2011	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$19	$19	$19	$19

Retained Earnings	13	13	10	10
Total Investment in PATH-WV	$32	$32	$29	$29

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,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Income Before Extraordinary Item	$ 487	$ 655	$ 1,238	$ 1,360
Extraordinary Item, Net of Tax	-	273	-	273
Net Income	$ 487	$ 928	$ 1,238	$ 1,633

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,			
	2012		2011	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 487		$ 928	
Weighted Average Number of Basic Shares Outstanding	485.0	$ 1.00	482.5	$ 1.92
Weighted Average Dilutive Effect of:				
Stock Options	0.1	-	0.1	-
Restricted Stock Units	0.3	-	0.2	-
Weighted Average Number of Diluted Shares Outstanding	485.4	$ 1.00	482.8	$ 1.92

	Nine Months Ended September 30,			
	2012		2011	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,238		$ 1,633	
Weighted Average Number of Basic Shares Outstanding	484.4	$ 2.55	481.9	$ 3.39
Weighted Average Dilutive Effect of:				
Stock Options	0.1	-	-	-
Restricted Stock Units	0.3	-	0.2	-
	484.8	$ 2.55	482.1	$ 3.39

Weighted Average Number of Diluted Shares Outstanding

Options to purchase 10,000 shares of common stock as of September 30, 2011 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. There were no antidilutive shares outstanding as of September 30, 2012.

Extraordinary Item

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the 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. 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.

2. RATE MATTERS

As discussed in the 2011 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2011 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 2012 and updates the 2011 Annual Report.

Regulatory Assets Not Yet Being Recovered

	September 30, 2012	December 31, 2011
	(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		
Storm Related Costs	$23	$24
Economic Development Rider	13	13
Other Regulatory Assets Not Yet Being Recovered	9	-
Regulatory Assets Currently Not Earning a Return		
Virginia Environmental Rate Adjustment Clause	23	18
Mountaineer Carbon Capture and Storage Product Validation Facility	14	14
Special Rate Mechanism for Century Aluminum	13	13
Litigation Settlement	11	11
Storm Related Costs	133	10
Virginia Deferred Wind Power Costs	4	38
Other Regulatory Assets Not Yet Being Recovered	29	14
Total Regulatory Assets Not Yet Being Recovered	$272	$155

If these costs are ultimately determined not to be recoverable, it would reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. See the “January 2012 – May 2016 ESP as Rejected by the PUCO” section below. The PUCO’s March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers’ Counsel and the Industrial Energy Users-Ohio (IEU)

filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could result in a refund of up to $698 million, excluding carrying costs.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. In May 2011, the IEU and the Ohio Energy Group (OEG) filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. The OEG's appeal seeks the inclusion of off-system sales (OSS) in the calculation of SEET which, if ordered, could require an additional refund of $22 million based on the PUCO approved SEET calculation. The IEU's appeal also sought the inclusion of OSS as well as other items in the determination of SEET, but did not quantify the amount. Oral arguments were held in March 2012 and management is unable to predict the outcome of the appeals.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included OSS in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO in 2012 on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo.

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.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved a modified stipulation which established a new ESP that included a standard service offer (SSO) pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the PIRR deferral in accordance with the 2009 - 2011 ESP order. Also in March 2012, OPCo filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. As of September 30, 2012, OPCo's net PIRR deferral was $536 million, excluding unrecognized equity carrying costs.

As a result of the PUCO's rejection of the modified stipulation, in the first quarter of 2012, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in the fourth quarter of 2011.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that will freeze base generation rates through May 2015, adopt a 12% earnings threshold for the SEET and allow the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the ESP approved a storm damage recovery mechanism which allowed OPCo to defer the majority of the incremental distribution operation and maintenance costs from 2012 storms. As of September 30, 2012, OPCo recorded $54 million in Regulatory Assets on the condensed balance sheets related to the 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of ESP and corporate separation orders and extending through December 2014. The PUCO also ordered OPCo to conduct an energy-only auction for a total of 60% of the SSO load with delivery beginning June 2014 through May 2015. In addition, the PUCO ordered OPCo to conduct an energy-only auction for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. Starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers to the extent that the total incurred capacity costs do not exceed $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. The order stated that the PUCO would establish an appropriate recovery mechanism in the June 2012 – May 2015 ESP proceeding. In July 2012, several parties, including OPCo, requested rehearing of the July 2012 PUCO order on capacity, which was upheld by the PUCO in October 2012.

In the August 2012 PUCO order which adopted and modified the new ESP, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide $508 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. In August 2012, the IEU filed a claim before the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss IEU's claim. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition.

In September 2012, OPCo and intervenors filed applications with the PUCO for rehearing of the August 2012 ESP order. Rehearing of this order is pending at the PUCO. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

Proposed Corporate Separation

In March 2012, OPCo filed an application with the PUCO for approval of the corporate separation of its generation assets including the transfer of generation assets to a nonregulated AEP subsidiary at net book value. In October 2012, the PUCO issued an order which approved the transfer of OPCo's generation assets at net book value to AEP Generation Resources, Inc. (AEPGenCo), a nonregulated affiliate in the Generation and Marketing segment. AEPGenCo will also assume the associated generation liabilities.

An additional filing at the FERC related to corporate separation is expected in the fourth quarter of 2012. Our results of operations related to generation in Ohio will be largely determined by our ability to sell power and capacity at a profit at rates determined by the prevailing market. If we are unable to sell power and capacity at a profit, it could reduce future net income and cash flows and impact financial condition.

2011 Ohio Distribution Base Rate Case

In February 2011, OPCo filed with the PUCO for an annual increase in distribution rates of $94 million based upon an 11.15% return on common equity to be effective January 2012. In December 2011, a stipulation was approved by the PUCO which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved by the modified stipulation in the ESP proceeding.

Since the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as filed in the ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. See the "June 2012 – May 2015 ESP Including Capacity Charge" section above.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultants' review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, an intervenor filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audits reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of September 30, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $38 million, including $20 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

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 filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent 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 OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through September 30, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. 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 these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could 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 scheduled to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.8 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $122 million for transmission, excluding AFUDC. As of September 30, 2012, excluding costs attributable to its joint owners and a $62 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.7 billion of expenditures, including AFUDC and capitalized interest of $296 million for generation and related transmission costs of $127 million. As of September 30, 2012, the joint owners and SWEPCo have contractual construction obligations of approximately $42 million, including related transmission costs of $3 million. SWEPCo's share of the contractual construction obligations is $31 million.

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. SWEPCo announced that it would continue construction of the Turk Plant and would

not currently seek authority to serve Arkansas retail customers from the Turk Plant. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. SWEPCo currently has no contracts for the 88 MW of Turk Plant output but is evaluating options.

The PUCT approved 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 (TIEC) 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. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and TIEC filed petitions for review at the Supreme Court of Texas. The Supreme Court of Texas has requested full briefing from the parties.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could materially reduce future net income and cash flows and materially impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operations and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant, Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures recovered from ratepayers and (c) included a return on and of the Stall Unit as of December 2011 and associated operations and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it could reduce future net income and cash flows and impact financial condition.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. Through September 30, 2012, SWEPCo has incurred $10 million related to this project, including AFUDC. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing at the APSC was held in October 2012 and a decision is pending from the APSC. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

APCo and WPCo Rate Matters

Virginia Fuel Filing

In April 2012, APCo filed an application with the Virginia SCC for an annual increase in fuel revenues of $117 million to be effective June 2012. The filing included forecasted costs for the 15-month period ended August 2013 and requested recovery of APCo's anticipated unrecovered fuel balance as of May 2012 over a two-year period commencing in June 2012. The non-incremental portion of APCo's forecasted and deferred wind purchased power

costs were reflected in APCo's filing. In June 2012, the Virginia SCC approved the application as filed.

Environmental Rate Adjustment Clause (Environmental RAC)

In November 2011, the Virginia SCC issued an order which approved APCo's environmental RAC recovery of $30 million to be collected over one year beginning in February 2012 but denied recovery of certain environmental costs. As a result, in the fourth quarter of 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. In December 2011, APCo filed a notice of appeal with the Supreme Court of Virginia regarding this decision. A decision is expected in the fourth quarter of 2012. If the Supreme Court of Virginia were to issue a favorable decision, it could increase future net income and cash flows.

Generation Rate Adjustment Clause (Generation RAC)

In January 2012, the Virginia SCC issued a generation RAC order which allowed APCo to recover $26 million annually, effective March 2012, related to recovery of the Dresden Plant. In March 2012, APCo filed with the Virginia SCC to continue the current generation RAC rate to recover costs of the Dresden Plant through February 2014. In August 2012, the Virginia SCC staff filed testimony that recommended a $5 million increase in the revenue requirement, including the under-recovered balance of $3 million as of April 2012. The Virginia SCC staff also recommended an alternative proposal to not change rates and not allow APCo to accrue carrying charges on any under-recovered generation RAC balances. A decision is expected in the fourth quarter of 2012. If the Virginia SCC were to disallow any portion of the generation RAC, it could reduce future net income and cash flows and impact financial condition.

APCo's Filings for an IGCC Plant

Through September 30, 2012, 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. 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 March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. Also in March 2012, APCo and WPCo filed their ENEC application with the WVPSC for the fourth year of a four-year phase-in plan which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral and other ENEC related assets. If the financing order is not issued, APCo and WPCo requested that recovery of these costs be allowed in current rates.

In July 2012, the WVPSC issued an interim order that approved a settlement agreement which recommended no change in total ENEC rates but reflected a $24 million increase in the construction surcharge and a $24 million decrease in ENEC rates. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to the December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. As of September 30, 2012, APCo's ENEC under-recovery balance of $307 million was recorded in Regulatory Assets on the condensed balance sheet, excluding $5 million of unrecognized equity carrying costs. A hearing is scheduled for December 2012.

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 prudence 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%. In October 2012, the OCC issued a final order that found PSO's fuel and purchased power costs were prudently incurred without any disallowance and that PSO's shareholder's portion of off-system sales margins would remain at 25%.

I&M Rate Matters

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015.

In May 2012, the Indiana Office of Utility Consumer Counselor filed testimony that recommended an increase in base rates of $28 million, excluding reductions to certain riders, based upon a return on common equity of 9.2%. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders. Final hearings were held in June 2012. A decision from the IURC is expected in the fourth quarter of 2012. If the IURC disallows cost recovery, it could reduce future net income and cash flows and impact financial condition.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant Units 1 and 2. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of September 30, 2012, I&M has incurred $109 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. A hearing at the IURC is scheduled for January 2013.

Also in August 2012, the MPSC staff and other intervenors filed testimony in Michigan. The recommendations ranged from the Association of Businesses Advocating Tariff Equity's denial of deferral of costs but recovery of costs considered in future base rate cases to the Attorney General allowing recovery of LCM project costs of $848 million. If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to

investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of September 30, 2012, we have incurred $48 million, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows.

In July 2012, certain intervenors filed testimony which recommended cost caps ranging from $1.1 billion to $1.4 billion if the IURC approved the CPCN. In addition, the Indiana Office of Utility Consumer Counselor recommended the CPCN be denied until a more detailed project plan and cost estimates are filed with the IURC. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. A hearing is scheduled for December 2012.

KPCo Rate Matters

Big Sandy Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system. KPCo is currently re-evaluating its options to meet the short and long-term energy needs of its customers at the most reasonable costs. As of September 30, 2012, KPCo has incurred $30 million related to the FGD project. Management intends to pursue recovery of all costs related to the FGD project. If KPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and 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. In 2006, a FERC Administrative Law Judge 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.

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 supported AEP's position and required a compliance filing. 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. A decision is pending from the FERC. Not all parties have agreed to the compliance filing.

The AEP East companies provided reserves for net refunds for SECA settlements. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, 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 members of the Interconnection Agreement gave notice to AEPSC and each other of its decision to terminate the Interconnection Agreement effective as of December 31, 2013 or such other date as ordered by the FERC. Management intends to file an application with the FERC in the fourth quarter of 2012 to terminate the Interconnection Agreement. It is unknown whether the Interconnection Agreement 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. If any of the members of the Interconnection Agreement experience decreases in revenues or increases in costs as a result of the termination of the Interconnection Agreement 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.

3. 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 2011 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 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 two credit facilities totaling $3.25 billion, under which we may issue up to $1.35 billion as letters of credit. As of September 30, 2012, the maximum future payments for letters of credit issued under the credit facilities were $132 million with maturities ranging from October 2012 to June 2013.

We have $402 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $407 million. The letters of credit have maturities ranging from March 2013 to July 2014.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. 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, 2012, SWEPCo has collected approximately $58 million through a rider for final mine closure and reclamation costs, of which $10 million is recorded in Other Current Liabilities, $7 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $41 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 2011 Annual Report "Dispositions" section of Note 6. As of September 30, 2012, there were no material liabilities recorded for any indemnifications.

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the 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. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of September 30, 2012, the maximum potential loss for these lease agreements was approximately $18 million assuming the fair value of the equipment is zero at the end of the lease term.

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 $15 million and $17 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2012.

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. The maximum potential losses related to the guarantee are approximately $12 million and $13 million for I&M and SWEPCo, respectively, 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 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. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. We will continue to 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 CO2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs have filed a petition for rehearing by the full court. We believe the action is without merit and will continue 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 $10 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.

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 cost approximately $400 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. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. 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, 2012, we recorded $64 million in Prepayments and Other Current Assets on our condensed balance sheets representing amounts recoverable from NEIL under the insurance policies. Through September 30, 2012, I&M received payments from NEIL of $203 million for the cost incurred to date to repair the property damage and $185 million under an accidental outage policy.

The claims process with NEIL continues and includes a review of claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies, 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. 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 reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

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) was among the companies named as defendants in some of these cases. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the dismissal of several cases involving AEP companies in Nevada to the Ninth Circuit Court of Appeals. Oral argument was held in October 2012. We will continue to defend the cases on appeal. We believe the provision we have is adequate. We believe the remaining exposure is immaterial.

4. ACQUISITION AND IMPAIRMENTS

ACQUISITION

2012

BlueStar Energy (Generation and Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million, subject to working capital adjustments. This transaction also included goodwill of $14 million, intangible assets associated with sales contracts and customer accounts of $59 million and liabilities associated with supply contracts of $25 million. These amounts are subject to revision once further evaluations are complete. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

IMPAIRMENTS

2012

Turk Plant (Utility Operations segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the condensed statements of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

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 the output of 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 Interconnection Agreement. 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.

5. 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, 2012 and 2011:

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Service Cost	$19	$18	$12	$11
Interest Cost	56	59	26	27
Expected Return on Plan Assets	(80)	(79)	(26)	(27)
Amortization of Transition Obligation	-	-	1	1
Amortization of Prior Service Cost (Credit)	-	1	(5)	(1)
Amortization of Net Actuarial Loss	42	31	14	8
Net Periodic Benefit Cost	$37	$30	$22	$19

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Service Cost	$57	$54	$35	$32
Interest Cost	167	178	78	81
Expected Return on Plan Assets	(239)	(236)	(76)	(81)
Amortization of Transition Obligation	-	-	1	1
Amortization of Prior Service Cost (Credit)	-	1	(14)	(1)
Amortization of Net Actuarial Loss	117	92	43	23
Net Periodic Benefit Cost	$102	$89	$67	$55

55

6. BUSINESS SEGMENTS

As outlined in our 2011 Annual Report, our primary business is the generation, transmission and distribution of electricity. 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. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

While our Utility Operations segment remains our primary business segment, the advancement of an area of our business prompted us to identify a new reportable segment. Starting in the fourth quarter of 2011, we established our new Transmission Operations segment as described below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

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

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a reportable 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 were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ended in the fourth quarter of 2011.

The tables below present our reportable segment information for the three and nine months ended September 30, 2012 and 2011 and balance sheet information as of September 30, 2012 and December 31, 2011. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's presentation.

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended September 30, 2012							
Revenues from:							
External Customers	$ 3,811	$ 3	$ 142	$ 194	$ 6	$ -	$ 4,156
Other Operating Segments	28	7	5	-	4	(44)	-
Total Revenues	$ 3,839	$ 10	$ 147	$ 194	$ 10	$ (44)	$ 4,156
Net Income (Loss)	$ 471	$ 14	$ (1)	$ 10	$ (6)	$ -	$ 488

	Utility Operations	Transmission Operations	Nonutility 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	3	6	-	4	(43)	-
Total Revenues	$ 4,074	$ 3	$ 183	$ 106	$ 10	$ (43)	$ 4,333
Income (Loss) Before Extraordinary Item	$ 633	$ 9	$ 17	$ 8	$ (10)	$ -	$ 657
Extraordinary Item, Net of Tax	273	-	-	-	-	-	273
Net Income (Loss)	$ 906	$ 9	$ 17	$ 8	$ (10)	$ -	$ 930

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			

Nine Months Ended September 30, 2012														
Revenues from:														
	External Customers	$	10,407	$	5	$	477	$	427	$	16	$	-	$	11,332
	Other Operating Segments		75		10		16		-		7		(108)		-
Total Revenues		$	10,482	$	15	$	493	$	427	$	23	$	(108)	$	11,332
Net Income (Loss)		$	1,220	$	31	$	11	$	4	$	(25)	$	-	$	1,241

	Utility Operations	Transmission Operations	AEP River Operations	Nonutility Operations Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Nine Months Ended September 30, 2011							
Revenues from:							
External Customers	$ 10,900	$ 1	$ 506	$ 247	$ 18	$ -	$ 11,672
Other Operating Segments	86	2	15	1	7	(111)	-
Total Revenues	$ 10,986	$ 3	$ 521	$ 248	$ 25	$ (111)	$ 11,672
Income (Loss) Before Extraordinary Item	$ 1,357	$ 19	$ 23	$ 20	$ (54)	$ -	$ 1,365
Extraordinary Item, Net of Tax	273	-	-	-	-	-	273
Net Income (Loss)	$ 1,630	$ 19	$ 23	$ 20	$ (54)	$ -	$ 1,638

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
September 30, 2012							
Total Property, Plant and Equipment	$ 55,859	$ 604	$ 632	$ 619	$ 11	$ (266)	$ 57,459
Accumulated Depreciation and Amortization	18,986	2	156	240	10	(68)	19,326
Total Property, Plant and Equipment - Net	$ 36,873	$ 602	$ 476	$ 379	$ 1	$ (198)	$ 38,133
Total Assets	$ 51,124	$ 1,008	$ 643	$ 1,022	$ 16,885	$ (16,839) (c)	$ 53,843

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2011							
Total Property, Plant and Equipment	$ 54,396	$ 323	$ 608	$ 590	$ 11	$ (258)	$ 55,670
Accumulated Depreciation and Amortization	18,393	-	136	219	10	(59)	18,699
Total Property, Plant and Equipment - Net	$ 36,003	$ 323	$ 472	$ 371	$ 1	$ (199)	$ 36,971
Total Assets	$ 50,093	$ 594	$ 659	$ 868	$ 16,751	$ (16,742) (c)	$ 52,223

(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 were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ended 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.

58

7. 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

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact. 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, 2012 and December 31, 2011:

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	September 30, 2012	December 31, 2011	Unit of Measure
	(in millions)		
Commodity:			
Power	617	609	MWhs
Coal	15	21	Tons
Natural Gas	123	100	MMBtus
Heating Oil and Gasoline	5	6	Gallons
Interest Rate	$ 258	$ 226	USD

Interest Rate and Foreign Currency	$	703	$	907	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

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

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities 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 future borrowings of fixed-rate debt. Our forecasted 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.

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, 2012 and December 31, 2011 balance sheets, we netted $18 million and $26 million, respectively, of cash collateral received from third parties against short-term and long-term risk management

assets and $48 million and $133 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, 2012 and December 31, 2011:

Fair Value of Derivative Instruments
September 30, 2012

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in millions)		
Current Risk Management Assets	$ 699	$ 36	$ 1	$ (561)	$ 175
Long-term Risk Management Assets	606	12	1	(229)	390
Total Assets	1,305	48	2	(790)	565
Current Risk Management Liabilities	656	35	37	(578)	150
Long-term Risk Management Liabilities	460	12	2	(250)	224
Total Liabilities	1,116	47	39	(828)	374
Total MTM Derivative Contract Net Assets (Liabilities)	$ 189	$ 1	$ (37)	$ 38	$ 191

Fair Value of Derivative Instruments
December 31, 2011

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in millions)		
Current Risk Management Assets	$ 852	$ 24	$ -	$ (683)	$ 193
Long-term Risk Management Assets	641	15	-	(253)	403
Total Assets	1,493	39	-	(936)	596
Current Risk Management Liabilities	847	29	20	(746)	150
	483	15	22	(325)	195

Long-term Risk Management Liabilities					
Total Liabilities	1,330	44	42	(1,071)	345
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163	$ (5)	$ (42)	$ 135	$ 251

(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, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2012 and 2011

Location of Gain (Loss)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Utility Operations Revenues	$ 5	$ 8	$ 19	$ 46
Other Revenues	20	6	28	21
Regulatory Assets (a)	2	(3)	(35)	(3)
Regulatory Liabilities (a)	(14)	(2)	12	8
Total Gain (Loss) on Risk Management Contracts	$ 13	$ 9	$ 24	$ 72

(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, 2012, we recognized gains of $1 million and $3 million, respectively, on our hedging instruments and offsetting losses of $1 million and $3 million, respectively, on our long-term debt. 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. During the three and nine months ended September 30, 2012 and 2011, hedge ineffectiveness was immaterial.

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 and natural gas 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, 2012 and 2011, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline 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, 2012 and 2011, 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) on our condensed balance sheets into Interest Expense on our condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2012 and 2011, 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, 2012 and 2011, we designated foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow 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, 2012 and 2011. 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, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of June 30, 2012	$ (14)	$ (30)	$ (44)
Changes in Fair Value Recognized in AOCI	16	(3)	13
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(1)	-	(1)
Purchased Electricity for Resale	-	-	-
Interest Expense	-	1	1
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2012	$ 1	$ (32)	$ (31)

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	Total
		(in millions)	
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 Statement of Income/within Balance Sheet:			
Utility Operations Revenues	1	-	1
Other Revenues	(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 Nine Months Ended September 30, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(7)	(15)	(22)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(4)	-	(4)
Purchased Electricity for Resale	13	-	13
Interest Expense	-	3	3
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2012	$ 1	$ (32)	$ (31)

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	Total
		(in millions)	
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 Statement of Income/within Balance Sheet:			
Utility Operations Revenues	3	-	3
Other Revenues	(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)

(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 as of September 30, 2012 and December 31, 2011 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 33	$ -	$ 33
Hedging Liabilities (a)	32	39	71
AOCI Gain (Loss) Net of Tax	1	(32)	(31)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	-	(4)	(4)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 20	$ -	$ 20
Hedging Liabilities (a)	25	42	67
AOCI Gain (Loss) Net of Tax	(3)	(20)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3)	(2)	(5)

(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, 2012, 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 36 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. AEP and its subsidiaries have not experienced 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, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 7	$ 32
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	44	39
Amount Attributable to RTO and ISO Activities	42	38

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. 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, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 519	$ 515
Amount of Cash Collateral Posted	3	56
Additional Settlement Liability if Cross Default Provision is Triggered	329	291

8. 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. Our market risk oversight staff independently monitors our valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of our Chief Operation Officer, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer.

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, FTRs and counterparty credit risk 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. The main driver of our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

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. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. 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.

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 classified as Level 2 measurement inputs. 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, 2012 and December 31, 2011 are summarized in the following table:

	September 30, 2012		December 31, 2011	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			

Long-term Debt	$ 17,227	$ 20,457	$ 16,516	$ 19,259

Fair Value Measurements of Other Temporary Investments

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

The following is a summary of Other Temporary Investments:

	September 30, 2012			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 197	$ -	$ -	$ 197
Fixed Income Securities:				
Mutual Funds	64	1	-	65
Equity Securities - Mutual Funds	11	5	-	16
Total Other Temporary Investments	$ 272	$ 6	$ -	$ 278

	December 31, 2011			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 216	$ -	$ -	$ 216
Fixed Income Securities:				
Mutual Funds	64	-	-	64
Equity Securities - Mutual Funds	11	3	-	14
Total Other Temporary Investments	$ 291	$ 3	$ -	$ 294

(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, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Proceeds from Investment Sales	$ -	$ 21	$ -	$ 268
Purchases of Investments	-	-	1	153
Gross Realized Gains on Investment Sales	-	4	-	4
Gross Realized Losses on Investment Sales	-	-	-	-

As of September 30, 2012 and December 31, 2011, we had no Other Temporary Investments with an unrealized loss position. As of September 30, 2012, 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.

69

The following tables provide details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on our balance sheet and the reasons for changes for the three and nine months ended September 30, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Three Months Ended September 30, 2012

		(in millions)
Balance in AOCI as of June 30, 2012	$	3
Changes in Fair Value Recognized in AOCI		1
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:		
Interest Income		-
Balance in AOCI as of September 30, 2012	$	4

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Nine Months Ended September 30, 2012

		(in millions)
Balance in AOCI as of December 31, 2011	$	2
Changes in Fair Value Recognized in AOCI		2
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:		
Interest Income		-
Balance in AOCI as of September 30, 2012	$	4

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 as of September 30, 2012 and December 31, 2011:

	September 30, 2012			December 31, 2011		
	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	$ 13	$ -	$ -	$ 18	$ -	$ -
Fixed Income Securities:						
United States Government	693	108	(1)	544	61	(1)
Corporate Debt	36	6	(1)	54	5	(2)
State and Local Government	226	1	(1)	330	-	(2)
Subtotal Fixed Income Securities	955	115	(3)	928	66	(5)
Equity Securities - Domestic	732	291	(78)	646	215	(80)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,700	$ 406	$ (81)	$ 1,592	$ 281	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Proceeds from Investment Sales	$ 182	$ 361	$ 699	$ 826
Purchases of Investments	199	379	744	871
Gross Realized Gains on Investment Sales	2	18	7	30
Gross Realized Losses on Investment Sales	1	12	3	21

The adjusted cost of fixed income securities was $840 million and $862 million as of September 30, 2012 and December 31, 2011, respectively. The adjusted cost of equity securities was $441 million and $431 million as of September 30, 2012 and December 31, 2011, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2012 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 136
1 year – 5 years	357
5 years – 10 years	265
After 10 years	197
Total	$ 955

71

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, 2012 and December 31, 2011. 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, 2012

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Cash and Cash Equivalents (a) (e)	$ 20	$ 1	$ -	$ 422	$ 443
Other Temporary Investments					
Restricted Cash (a) (e)	183	5	-	9	197
Fixed Income Securities:					
Mutual Funds	65	-	-	-	65
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	264	5	-	9	278
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	47	1,076	166	(778)	511
Cash Flow Hedges:					
Commodity Hedges (c)	9	37	2	(15)	33
Fair Value Hedges	-	2	-	-	2
De-designated Risk Management Contracts (d)	-	-	-	19	19
Total Risk Management Assets	56	1,115	168	(774)	565
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	5	-	8	13
Fixed Income Securities:					
United States Government	-	693	-	-	693
Corporate Debt	-	36	-	-	36
State and Local Government	-	226	-	-	226
Subtotal Fixed Income Securities	-	955	-	-	955
Equity Securities - Domestic (b)	732	-	-	-	732
Total Spent Nuclear Fuel and Decommissioning Trusts	732	960	-	8	1,700
Total Assets	$ 1,072	$ 2,081	$ 168	$ (335)	$ 2,986
Liabilities:					

Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 42	$ 994	$ 64	$ (797)	$ 303
Cash Flow Hedges:					
Commodity Hedges (c)	-	47	-	(15)	32
Interest Rate/Foreign Currency Hedges	-	39	-	-	39
Total Risk Management Liabilities	$ 42	$ 1,080	$ 64	$ (812)	$ 374

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ -	$ -	$ 215	$ 221
Other Temporary Investments					
Restricted Cash (a)	191	-	-	25	216
Fixed Income Securities:					
Mutual Funds	64	-	-	-	64
Equity Securities - Mutual Funds (b)	14	-	-	-	14
Total Other Temporary Investments	269	-	-	25	294
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	47	1,299	147	(945)	548
Cash Flow Hedges:					
Commodity Hedges (c)	15	23	-	(18)	20
De-designated Risk Management Contracts (d)	-	-	-	28	28
Total Risk Management Assets	62	1,322	147	(935)	596
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	5	-	13	18
Fixed Income Securities:					
United States Government	-	544	-	-	544
Corporate Debt	-	54	-	-	54
State and Local Government	-	330	-	-	330
Subtotal Fixed Income Securities	-	928	-	-	928
Equity Securities - Domestic (b)	646	-	-	-	646
Total Spent Nuclear Fuel and Decommissioning Trusts	646	933	-	13	1,592
Total Assets	$ 983	$ 2,255	$ 147	$ (682)	$ 2,703
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 43	$ 1,209	$ 78	$ (1,052)	$ 278
Cash Flow Hedges:					
Commodity Hedges (c)	-	43	-	(18)	25
Interest Rate/Foreign Currency Hedges	-	42	-	-	42
Total Risk Management Liabilities	$ 43	$ 1,294	$ 78	$ (1,070)	$ 345

(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, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $12 million in periods 2013-2015 and ($7) million in periods 2016-2018; Level 2 matures $59 million in periods 2013-2015, $14 million in periods 2016-2017 and $9 million in periods 2018-2030; Level 3 matures $7 million in 2012, $35 million in periods 2013-2015, $31 million in periods 2016-2017 and $29 million in periods 2018-2030. Risk management commodity contracts are substantially comprised of power contracts.

(g) The December 31, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $3 million in 2012, $7 million in periods 2013-2015 and ($6) million in periods 2016-2018; Level 2 matures $21 million in 2012, $50 million in periods 2013-2015, $11 million in periods 2016-2017 and $8 million in periods 2018-2030; Level 3 matures ($19) million in 2012, $44 million in periods 2013-2015, $18 million in periods 2016-2017 and $26 million in periods 2018-2030. 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, 2012 and 2011.

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, 2012	Net Risk Management Assets (Liabilities) (in millions)
Balance as of June 30, 2012	$ 97
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(5)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	7
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	5
Purchases, Issuances and Settlements (c)	4
Transfers into Level 3 (d) (f)	(3)
Transfers out of Level 3 (e) (f)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	-
Balance as of September 30, 2012	$ 104

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

Nine Months Ended September 30, 2012	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2011	$ 69
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)	20
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	2
Purchases, Issuances and Settlements (c)	33
Transfers into Level 3 (d) (f)	10
Transfers out of Level 3 (e) (f)	(21)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7
Balance as of September 30, 2012	$ 104

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

(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.

The following table quantifies the significant unobservable inputs used in developing the fair value of our Level 3 positions as of September 30, 2012:

	Fair Value		Valuation	Significant Unobservable	Input/Range	
	Assets	Liabilities	Technique	Input	Low	High
	(in millions)					
Energy Contracts	$ 160	$ 57	Discounted Cash Flow	Forward Market Price (a)	$ 10.45	$ 117.64
				Counterparty Credit Risk (b)	457	
FTRs	8	7	Discounted Cash Flow	Forward Market Price (a)	(7.71)	9.92
Total	$ 168	$ 64				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

9. INCOME TAXES

AEP System Tax Allocation Agreement

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.

Federal and State Income Tax Audit Status

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 did 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 impact 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. In March 2012, AEP settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not have a material impact on net income, cash flows or financial condition.

Uncertain Tax Positions

We filed the 2011 federal income tax return during the third quarter of 2012. The return includes deductions which are not recognized in the financial statements. This resulted in a $121 million increase in unrecognized tax benefits. The increase in unrecognized tax benefits did not have an impact on net income, cash flows or financial condition and there was no change in the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate.

State Tax Legislation

During the third quarter of 2012, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not have a material impact on net income, cash flows or financial condition.

10. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	September 30, 2012	December 31, 2011
	(in millions)	
Senior Unsecured Notes	$ 11,883	$ 11,737
Pollution Control Bonds	1,958	2,112
Notes Payable	469	402
Securitization Bonds	2,316	1,688
Junior Subordinated Debentures	315	315
Spent Nuclear Fuel Obligation (a)	265	265
Other Long-term Debt	51	29
Fair Value of Interest Rate Hedges	6	7
Unamortized Discount, Net	(36)	(39)
Total Long-term Debt Outstanding	17,227	16,516
Long-term Debt Due Within One Year	2,272	1,433
Long-term Debt	$ 14,955	$ 15,083

(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 as of both September 30, 2012 and December 31, 2011 and are included in Spent Nuclear Fuel and Decommissioning Trusts on our condensed balance sheets.

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2012 are shown in the tables below:

Company Issuances:	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
APCo	Senior Unsecured Notes	$ 275	Variable	2013
APCo	Pollution Control Bonds	65	2.25	2016
I&M	Notes Payable	110	Variable	2016
I&M	Other Long-term Debt	20 (a)	Variable	2015
PSO	Notes Payable	2	3.00	2027
SWEPCo	Senior Unsecured Notes	275	3.55	2022
SWEPCo	Notes Payable	65	4.58	2032
Non-Registrant:				
TCC	Securitization Bonds	312	2.845	2024
TCC	Securitization Bonds	308	0.88	2017
TCC	Securitization Bonds	180	1.976	2020
Total Issuances		$ 1,612 (b)		

(a) Consists of a $110 million three-year credit facility to be used for general corporate purposes.

(b) Amount indicated on the statement of cash flows of $1.6 billion is net of issuance costs and premium or discount.

Company Retirements and Principal Payments:	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
APCo	Pollution Control Bonds	$ 30	6.05	2024
APCo	Pollution Control Bonds	20	5.00	2021
APCo	Pollution Control Bonds	65	2.00	2012
APCo	Senior Unsecured Notes	250	5.65	2012
I&M	Notes Payable	14	5.44	2013
I&M	Notes Payable	11	4.00	2014
I&M	Notes Payable	15	Variable	2015
I&M	Notes Payable	18	Variable	2016
I&M	Notes Payable	12	2.12	2016
I&M	Notes Payable	8	Variable	2016
OPCo	Pollution Control Bonds	45	4.85	2012
OPCo	Senior Unsecured Notes	150	Variable	2012
SWEPCo	Notes Payable	20	7.03	2012
SWEPCo	Notes Payable	2	4.58	2032

Non-Registrant:				
AEP Subsidiaries	Notes Payable	8	Variable	2017
AEP Subsidiaries	Notes Payable	2	7.59-8.03	2026
AEGCo	Senior Unsecured Notes	3	6.33	2037
TCC	Securitization Bonds	108	4.98	2013
TCC	Securitization Bonds	63	5.96	2013
TCC	Pollution Control Bonds	60	1.125	2012
Total Retirements and Principal Payments		$ 904		

In October 2012, I&M retired $29 million of Notes Payable related to DCC Fuel.

In October 2012, AEGCo retired $4 million of 6.33% Senior Unsecured Notes due in 2037.

In October 2012, AEP Transmission Company, LLC issued $250 million of Senior Notes in three tranches. The tranches are $104 million at 3.3% due in 2022, $85 million at 4% due in 2032 and $61 million at 4.73% due in 2042.

As of September 30, 2012, trustees held, on our behalf, $583 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 financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%.

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 book value of the common stock. 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:

Type of Debt	September 30, 2012 Outstanding Amount (in millions)	September 30, 2012 Interest Rate (a)	December 31, 2011 Outstanding Amount (in millions)	December 31, 2011 Interest Rate (a)
Securitized Debt for Receivables (b)	$ 696	0.24 %	$ 666	0.27 %
Commercial Paper	520	0.45 %	967	0.51 %
Line of Credit – Sabine (c)	-	- %	17	1.79 %

Total Short-term Debt	$ 1,216	$ 1,650

(a) Weighted average rate.

(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

(c) 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 3.

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 June 2012, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.26 %	0.23 %	0.26 %	0.27 %
Net Uncollectible Accounts Receivable Written Off	$ 8	$ 11	$ 21	$ 28

	September 30, 2012	December 31, 2011
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 887	$ 902
Total Principal Outstanding	696	666
Delinquent Securitized Accounts Receivable	41	38
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	22	18
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	236	370

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.

11. SUSTAINABLE COST REDUCTIONS

In April 2012, we initiated a process to identify employee repositioning opportunities and efficiencies that will result in sustainable cost savings. The process will result in involuntary severances and is expected to be completed in early 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded charges to expense in 2012 related to the sustainable cost reductions initiative.

		Total (in millions)
Incurred	$	14
Settled		(12)
Remaining Balance as of September 30, 2012	$	2

These expenses relate primarily to severance benefits. They are included primarily in Other Operation on the condensed statements of income and Other Current Liabilities on the condensed balance sheets. Approximately 94% of the expense was within the Utility Operations segment. At this time, we are unable to estimate the total amount to be incurred in future periods related to this initiative or to quantify the effects on future net income, cash flows and financial condition.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

West Virginia Regulatory Activity

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework to securitize certain deferred Expanded Net Energy Charge (ENEC) balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. A hearing is scheduled in December 2012.

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. In December 2011 and February 2012, APCo and WPCo filed merger applications with the WVPSC and the FERC, respectively. In February 2012, APCo and WPCo withdrew their merger application with the FERC. Management intends to refile a merger application with the FERC and also file a merger application with the Virginia SCC in the fourth quarter of 2012.

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 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2011 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 150. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 207 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,	
	2012	2011	2012	2011
	(in millions of KWhs)			
Retail:				
Residential	2,741	2,854	8,375	9,180
Commercial	1,804	1,861	5,112	5,254

Industrial	2,712	2,738	8,018	8,056
Miscellaneous	202	204	604	617
Total Retail (a)	7,459	7,657	22,109	23,107
Wholesale	2,745	3,072	5,618	7,235
Total KWhs	10,204	10,729	27,727	30,342

(a) Represents energy delivered to distribution customers.

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,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	3	3	986	1,389
Normal - Heating (b)	3	3	1,443	1,440
Actual - Cooling (c)	892	955	1,336	1,425
Normal - Cooling (b)	817	807	1,178	1,161

(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 2012 Compared to Third Quarter of 2011

Reconciliation of Third Quarter of 2011 to Third Quarter of 2012
Net Income
(in millions)

Third Quarter of 2011	$	53
Changes in Gross Margin:		
Retail Margins		47
Off-system Sales		(3)
Transmission Revenues		3
Other Revenues		1
Total Change in Gross Margin		48
Changes in Expenses and Other:		
Other Operation and Maintenance		(9)
Depreciation and Amortization		(18)
Taxes Other Than Income Taxes		(1)
Carrying Costs Income		(4)
Other Income		(4)
Interest Expense		1
Total Change in Expenses and Other		(35)
Income Tax Expense		(3)
Third Quarter of 2012	$	63

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 electricity were as follows:

- Retail Margins increased $47 million primarily due to the following:
  - A $24 million increase due to higher rates in Virginia. For this increase, $18 million has a corresponding increase in Depreciation and Amortization expenses below.
  - A $17 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily as a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sporn Unit 5 from the Interconnection Agreement in September 2011.
  - A $4 million decrease in other variable electric generation expenses.

  These increases were partially offset by:
  - A $5 million decrease in residential and commercial margins primarily due to lower non-weather related usage.
  - A $4 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days.
- Margins from Off-system Sales decreased $3 million primarily due to lower market prices and reduced physical sales volumes.

· Transmission Revenues increased $3 million primarily due to increased Network Integrated Transmission Service (NITS) revenue. These revenues are offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $9 million primarily due to the following:
  - A $10 million increase in provisions for uncollectible accounts.
  - A $3 million increase in transmission expenses due to higher NITS expenses. These expenses are offset in Transmission Revenues above.

  These increases were partially offset by:
  - A $3 million decrease in generation plant maintenance expense in 2012.
- Depreciation and Amortization expenses increased $18 million primarily due to:
  - A $10 million increase as a result of increased depreciation rates in Virginia effective February 2012. The majority of this increase in depreciation is offset within Gross Margin.
  - A $4 million increase in amortization as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012. This increase in amortization is offset within Gross Margin.
- Carrying Costs Income decreased $4 million primarily due to lower carrying costs on the Virginia Environmental Rate Adjustment Clause and the Expanded Net Energy Charge.
- Other Income decreased $4 million primarily due to:
  - A $2 million decrease due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
  - A $2 million decrease in the equity component of AFUDC as a result of the completion of the Dresden Plant in January 2012.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income and state income tax adjustments related to prior year tax returns partially offset by other book/tax differences which are accounted for on a flow through basis.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Reconciliation of Nine Months Ended September 30, 2011 to Nine Months Ended September 30, 2012
Net Income
(in millions)

Nine Months Ended September 30, 2011	$	123
Changes in Gross Margin:		
Retail Margins		141
Off-system Sales		(9)
Transmission Revenues		8
Other Revenues		(2)
Total Change in Gross Margin		138
Changes in Expenses and Other:		
Other Operation and Maintenance		37
Depreciation and Amortization		(47)
Other Income		(6)
Interest Expense		4
Total Change in Expenses and Other		(12)
Income Tax Expense		(48)
Nine Months Ended September 30, 2012	$	201

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 electricity were as follows:

- Retail Margins increased $141 million primarily due to the following:
  - A $67 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily as a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sporn Unit 5 from the Interconnection Agreement in September 2011.
  - A $56 million increase due to higher rates in Virginia and West Virginia. For this increase, $39 million have a corresponding increase in Depreciation and Amortization expenses below.
  - A $22 million decrease in other variable electric generation expenses.
  - A $9 million deferral of additional wind purchase recovery costs as a result of the June 2012 Virginia SCC fuel factor order.
  - A $7 million decrease in PJM expenses.

  These increases were partially offset by:
  - A $37 million decrease in weather-related usage primarily due to a 29% decrease in heating degree days.
  - A $14 million decrease in residential margins primarily due to lower non-weather related usage.

- Margins from Off-system Sales decreased $9 million primarily due to lower market prices, reduced physical sales volumes and lower trading and marketing margins.
- Transmission Revenues increased $8 million primarily due to increased NITS revenue requirements beginning in July 2011. These NITS revenues are offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses decreased $37 million primarily due to the following:
  - A $41 million decrease 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 $15 million decrease in generation plant maintenance expenses in 2012.
  - A $14 million decrease due to the deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC.
  - A $9 million decrease in storm restoration expenses and vegetation management.
  - A $7 million decrease in general administrative expenses.

  These decreases were partially offset by:
  - A $32 million increase due to the first quarter 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC in 2011.
  - An $11 million increase in transmission expenses due to higher NITS expenses. These expenses are offset in Transmission Revenues above.
  - An $11 million increase in provisions for uncollectible accounts.
  - A $3 million increase due to expenses related to the 2012 sustainable cost reductions.
- Depreciation and Amortization expenses increased $47 million primarily due to:
  - A $26 million increase as a result of increased depreciation rates in Virginia effective February 2012. The majority of this increase in depreciation is offset within Gross Margin.
  - A $10 million increase in amortization as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - A $4 million increase in depreciation as a result of Dresden Plant being placed in service in January 2012.
- Other Income decreased $6 million primarily due to:
  - A $4 million decrease in the equity component of AFUDC as a result of the completion of the Dresden Plant in January 2012.
  - A $2 million decrease due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- Interest Expense decreased $4 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense increased $48 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2011 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 Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 207 for a discussion of accounting pronouncements.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$776,066	$757,366	$2,161,901	$2,175,163
Sales to AEP Affiliates	84,940	98,419	216,284	259,641
Other Revenues	3,192	2,551	7,950	6,797
TOTAL REVENUES	864,198	858,336	2,386,135	2,441,601
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	241,448	230,318	609,985	595,597
Purchased Electricity for Resale	45,196	57,370	155,421	195,715
Purchased Electricity from AEP Affiliates	181,134	222,164	463,015	630,014
Other Operation	92,700	80,376	239,704	268,269
Maintenance	47,047	50,172	131,212	139,628
Depreciation and Amortization	86,636	68,749	252,188	205,492
Taxes Other Than Income Taxes	27,315	26,471	79,272	79,542
TOTAL EXPENSES	721,476	735,620	1,930,797	2,114,257
OPERATING INCOME	142,722	122,716	455,338	327,344
Other Income (Expense):				
Interest Income	332	2,477	1,034	3,559
Carrying Costs Income	3,950	7,579	17,202	17,560
Allowance for Equity Funds Used During Construction	443	2,451	960	4,546
Interest Expense	(50,071)	(51,196)	(153,323)	(157,323)
INCOME BEFORE INCOME TAX EXPENSE	97,376	84,027	321,211	195,686
Income Tax Expense	34,185	31,223	120,377	72,275
NET INCOME	63,191	52,804	200,834	123,411
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	199	-	599
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$63,191	$52,605	$200,834	$122,812

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Net Income	$ 63,191	$ 52,804	$ 200,834	$ 123,411
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $925 and $239 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $940 and $413 for the Nine Months Ended September 30, 2012 and 2011, Respectively	1,719	(444)	1,746	767
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $484 and $418 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $1,453 and $1,255 for the Nine Months Ended September 30, 2012 and 2011, Respectively	899	778	2,698	2,332
TOTAL OTHER COMPREHENSIVE INCOME	2,618	334	4,444	3,099
TOTAL COMPREHENSIVE INCOME	$ 65,809	$ 53,138	$ 205,278	$ 126,510

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Net Income			123,411		123,411
Other Comprehensive Income				3,099	3,099
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$260,458	$1,575,499	$1,159,060	$ (44,924)	$2,950,093
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$260,458	$1,573,752	$1,160,747	$ (58,543)	$2,936,414
Common Stock Dividends			(135,000)		(135,000)
Subtotal – Common Shareholder's Equity					2,801,414
Net Income			200,834		200,834
Other Comprehensive Income				4,444	4,444
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2012	$260,458	$1,573,752	$1,226,581	$ (54,099)	$3,006,692

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2012 and December 31, 2011
(in thousands)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,575	$ 2,317
Advances to Affiliates	22,767	22,008
Accounts Receivable:		
Customers	159,974	158,382
Affiliated Companies	70,043	136,194
Accrued Unbilled Revenues	48,717	68,427
Miscellaneous	458	5,505
Allowance for Uncollectible Accounts	(10,884)	(5,289)
Total Accounts Receivable	268,308	363,219
Fuel	187,181	143,931
Materials and Supplies	102,481	101,724
Risk Management Assets	31,227	39,645
Accrued Tax Benefits	18,170	7,715
Regulatory Asset for Under-Recovered Fuel Costs	88,713	41,105
Prepayments and Other Current Assets	19,682	21,745
TOTAL CURRENT ASSETS	740,104	743,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,577,549	5,194,967
Transmission	2,007,720	1,943,969
Distribution	2,937,648	2,845,405
Other Property, Plant and Equipment	381,235	357,326
Construction Work in Progress	283,775	565,841
Total Property, Plant and Equipment	11,187,927	10,907,508
Accumulated Depreciation and Amortization	3,162,532	2,994,016
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,025,395	7,913,492
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,416,426	1,481,193
Long-term Risk Management Assets	38,371	39,226
Deferred Charges and Other Noncurrent Assets	100,444	122,187
TOTAL OTHER NONCURRENT ASSETS	1,555,241	1,642,606
TOTAL ASSETS	$ 10,320,740	$ 10,299,507

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2012 and December 31, 2011
(Unaudited)

	2012	2011
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 117,574	$ 198,248
Accounts Payable:		
General	189,323	186,612
Affiliated Companies	100,849	137,376
Long-term Debt Due Within One Year – Nonaffiliated	574,678	594,525
Risk Management Liabilities	18,326	26,606
Customer Deposits	63,459	61,690
Deferred Income Taxes	33,145	14,255
Accrued Taxes	55,075	63,422
Accrued Interest	67,110	57,230
Other Current Liabilities	105,825	105,646
TOTAL CURRENT LIABILITIES	1,325,364	1,445,610
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,127,605	3,131,726
Long-term Risk Management Liabilities	20,805	12,923
Deferred Income Taxes	1,802,416	1,736,180
Regulatory Liabilities and Deferred Investment Tax Credits	601,926	576,792
Employee Benefits and Pension Obligations	283,506	302,182
Deferred Credits and Other Noncurrent Liabilities	152,426	157,680
TOTAL NONCURRENT LIABILITIES	5,988,684	5,917,483
TOTAL LIABILITIES	7,314,048	7,363,093
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
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	1,573,752	1,573,752
Retained Earnings	1,226,581	1,160,747
Accumulated Other Comprehensive Income (Loss)	(54,099)	(58,543)
TOTAL COMMON SHAREHOLDER’S EQUITY	3,006,692	2,936,414
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,320,740	$ 10,299,507

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

92

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 200,834	$ 123,411
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	252,188	205,492
Deferred Income Taxes	84,850	184,986
Carrying Costs Income	(17,202)	(17,560)
Deferral of Storm Costs	(57,638)	(16,977)
Allowance for Equity Funds Used During Construction	(960)	(4,546)
Mark-to-Market of Risk Management Contracts	10,284	13,161
Property Taxes	20,056	19,231
Fuel Over/Under-Recovery, Net	61,404	(20,603)
Change in Other Noncurrent Assets	(35,501)	11,121
Change in Other Noncurrent Liabilities	7,155	1,014
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	94,528	124,404
Fuel, Materials and Supplies	(44,007)	132,579
Accounts Payable	(27,443)	(72,682)
Accrued Taxes, Net	(709)	(54,214)
Other Current Assets	1,754	13,023
Other Current Liabilities	12,128	3,984
Net Cash Flows from Operating Activities	561,721	645,824
INVESTING ACTIVITIES		
Construction Expenditures	(323,866)	(300,357)
Change in Advances to Affiliates, Net	(759)	(81,825)
Acquisitions of Assets	(171)	(302,217)
Other Investing Activities	8,051	11,885
Net Cash Flows Used for Investing Activities	(316,745)	(672,514)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	100,000
Issuance of Long-term Debt – Nonaffiliated	339,396	640,027
Change in Advances from Affiliates, Net	(80,674)	(128,331)
Retirement of Long-term Debt – Nonaffiliated	(364,868)	(479,666)
Retirement of Cumulative Preferred Stock	-	(8)
Principal Payments for Capital Lease Obligations	(4,873)	(5,546)
Dividends Paid on Common Stock	(135,000)	(97,500)
Dividends Paid on Cumulative Preferred Stock	-	(599)
Other Financing Activities	301	31
Net Cash Flows from (Used for) Financing Activities	(245,718)	28,408

Net Increase (Decrease) in Cash and Cash Equivalents		(742)		1,718
Cash and Cash Equivalents at Beginning of Period		2,317		951
Cash and Cash Equivalents at End of Period	$	1,575	$	2,669
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	137,992	$	145,969
Net Cash Paid (Received) for Income Taxes		10,870		(74,384)
Noncash Acquisitions Under Capital Leases		2,338		697
Government Grants Included in Accounts Receivable as of September 30,		-		137
Construction Expenditures Included in Current Liabilities as of September 30,		59,041		60,265

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

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 150.

	Footnote Reference
Significant Accounting Matters	Note 1
Rate Matters	Note 2
Commitments, Guarantees and Contingencies	Note 3
Acquisition and Impairments	Note 4
Benefit Plans	Note 5
Business Segments	Note 6
Derivatives and Hedging	Note 7
Fair Value Measurements	Note 8
Income Taxes	Note 9
Financing Activities	Note 10
Sustainable Cost Reductions	Note 11

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

95

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

EXECUTIVE OVERVIEW

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015.

In May 2012, the Indiana Office of Utility Consumer Counselor filed testimony that recommended an increase in base rates of $28 million, excluding reductions to certain riders, based upon a return on common equity of 9.2%. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders. Final hearings were held in June 2012. A decision from the IURC is expected in the fourth quarter of 2012. See "2011 Indiana Base Rate Case" section of Note 2.

Michigan Capacity Rate

In April 2012, the FERC issued an order, effective October 2012, which sets I&M's capacity cost to be charged to alternative electric suppliers (AES) serving switching customers in I&M's Michigan service territory at $394/MW day unless a state compensation mechanism is approved by the MPSC. In May 2012, the MPSC issued an order to initiate a proceeding to establish a cost of service state compensation mechanism for the capacity rate to be charged to AES. In September 2012, the MPSC approved I&M's filed cost of service proposal with a minor adjustment recommended by the MPSC staff. Under Michigan law, switching is limited to 10% of I&M's Michigan load, which was achieved in June 2012, the second month of customer switching.

Cook Plant

Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 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. 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 would reduce future net income and cash flows and impact financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 3.

Nuclear Regulatory Commission

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, the Nuclear Regulatory Commission (NRC) initiated a review of safety procedures and requirements for nuclear generating facilities. As a result, the NRC issued orders and guidance that increase procedures and testing requirements, require physical modifications to the plant and will increase future operating costs at the Cook Plant. Management anticipates that

future cumulative compliance costs will range from $40 million to $50 million. Approximately half of this estimate is expected to be capital. The remainder will be operating expenses that generally is expected to be incurred over the plant's life.

The NRC is also looking into the fuel used at eleven reactors, including the units at the Cook Plant. Their concern relates to fuel temperatures if abnormal conditions are experienced. Management continues to monitor this issue and responds to the NRC's inquiry, as necessary. In addition to the review by the NRC, Congress could consider legislation increasing oversight of nuclear generating facilities. Management is unable to predict the impact of potential future regulation of nuclear facilities.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant Units 1 and 2. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In Indiana, I&M requested recovery of certain project costs, including interest, through a rider effective January 2013. A hearing at the IURC is scheduled for January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of September 30, 2012, I&M has incurred $109 million related to the LCM Project, including AFUDC. Several intervenors filed testimony with various recommendations. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows. See "Cook Plant Life Cycle Management Project" section of Note 2.

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 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2011 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 150. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 207 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,	
	2012	2011	2012	2011
	(in millions of KWhs)			
Retail:				
Residential	1,652	1,657	4,438	4,662
Commercial	1,370	1,392	3,826	3,844
Industrial	1,887	1,920	5,684	5,635
Miscellaneous	16	14	54	52

Total Retail (a)	4,925	4,983	14,002	14,193
Wholesale	3,009	3,024	7,039	7,529
Total KWhs	7,934	8,007	21,041	21,722

(a) Represents energy delivered to distribution customers.

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,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	19	15	1,803	2,635
Normal - Heating (b)	11	11	2,431	2,425
Actual - Cooling (c)	696	767	1,095	1,071
Normal - Cooling (b)	594	585	851	837

(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 2012 Compared to Third Quarter of 2011

Reconciliation of Third Quarter of 2011 to Third Quarter of 2012
Net Income
(in millions)

Third Quarter of 2011	$	52
Changes in Gross Margin:		
Retail Margins		3
FERC Municipals and Cooperatives		(3)
Off-system Sales		(4)
Transmission Revenues		(2)
Other Revenues		(5)
Total Change in Gross Margin		(11)
Changes in Expenses and Other:		
Other Operation and Maintenance		(2)
Depreciation and Amortization		(5)
Taxes Other Than Income Taxes		(2)
Other Income		(2)
Interest Expense		(2)
Total Change in Expenses and Other		(13)
Income Tax Expense		11
Third Quarter of 2012	$	39

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 electricity were as follows:

- Retail Margins increased $3 million primarily due to the following:
  - An $8 million increase due to customer credits issued in 2011 for a settlement relating to the Cook Plant Unit 1 (Unit 1) fire outage. This increase was offset by an increase in Other Operation and Maintenance expenses as discussed below.
  - A $3 million increase in rate recovery primarily due to higher PJM rider revenue. The increase in PJM revenues is offset by a corresponding increase in Other Operation and Maintenance expenses below.

  These increases were offset by:
  - An $11 million decrease in capacity settlement revenues under the Interconnection Agreement, net of sharing with customers in Michigan. This decrease was primarily a result of a mild winter in 2012 and its impact on APCo's winter peak.
- Margins from FERC Municipals and Cooperatives decreased $3 million primarily due to an annual rate adjustment to actual costs.
- Margins from Off-system Sales decreased $4 million primarily due to lower market prices and reduced physical sales volumes.
-

Other Revenues decreased $5 million primarily due to decreased I&M's River Transportation Division (RTD) revenues from barging activities as a result of the 2012 drought's impact on river conditions.

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

- Other Operation and Maintenance expenses increased $2 million primarily due to the following:
  - An $8 million increase in steam power expenses related to credits issued in 2011 associated with the Unit 1 fire outage. This increase was offset by an increase in Retail Margins as discussed above.
  - A $6 million increase associated with the favorable resolution of a contingency in 2011.
  - A $5 million increase in storm restoration expenses.

  These increases were partially offset by:
  - A $6 million decrease in RTD expenses from barging activities. The decrease in RTD expense was offset by a corresponding decrease in Other Revenues from barging activities as discussed above.
  - A $5 million decrease in maintenance costs due to the 2011 Cook Plant outage.
  - A $5 million decrease in distribution and transmission maintenance expenses primarily due to decreased overhead line expenses.
- Depreciation and Amortization expenses increased $5 million primarily due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life as approved in the Michigan base case settlement effective April 2012. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
- Income Tax Expense decreased $11 million primarily due to a decrease in pretax book income and other book/tax differences which are accounted for on a flow through basis partially offset by the regulatory accounting treatment of state income taxes.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Reconciliation of Nine Months Ended September 30, 2011 to Nine Months Ended September 30, 2012
Net Income
(in millions)

Nine Months Ended September 30, 2011	$	129
Changes in Gross Margin:		
Retail Margins		(16)
FERC Municipals and Cooperatives		(6)
Off-system Sales		(12)
Total Change in Gross Margin		(34)
Changes in Expenses and Other:		
Other Operation and Maintenance		3
Depreciation and Amortization		(9)
Other Income		(2)
Interest Expense		(3)
Total Change in Expenses and Other		(11)
Income Tax Expense		24
Nine Months Ended September 30, 2012	$	108

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 electricity were as follows:

- Retail Margins decreased $16 million primarily due to the following:
  - A $41 million decrease in capacity settlement revenues under the Interconnection Agreement, net of sharing with customers in Michigan. This decrease was primarily a result of a mild winter in 2012 and its impact on APCo's winter peak.
  - A $10 million decrease in weather-related usage primarily due to a 32% decrease in heating degree days.

  These decreases were partially offset by:
  - A $22 million increase in rate recovery primarily due to higher PJM rider revenue, Michigan base rate increases and higher Indiana Demand Side Management (DSM) revenue. These increases are offset by a corresponding increase in other expense items as discussed below.
  - A $14 million increase due to customer credits issued in 2011 for a settlement relating to the Unit 1 fire outage. This increase was offset by an increase in Other Operation and Maintenance expenses as discussed below.
- Margins from FERC Municipals and Cooperatives decreased $6 million primarily due to the following:
  - A $13 million decrease due to an annual rate adjustment to actual costs.

  This decrease was partially offset by:
  - A $7 million increase due to favorable fuel adjustments.
-

Margins from Off-system Sales decreased $12 million primarily due to lower market prices, reduced physical sales volumes and lower trading and marketing margins.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
  - A $13 million decrease primarily due to maintenance outages at the Tanners Creek and Rockport plants in 2011.
  - A $7 million decrease in distribution operation and maintenance expenses primarily due to decreased overhead line expenses.
  - A $4 million decrease in RTD expenses from barging activities. The decrease in RTD expense was partially offset by a corresponding decrease in Other Revenues from barging activities.
  - A $3 million decrease in transmission maintenance expenses.

  These decreases were partially offset by:
  - A $14 million increase in steam power expenses related to credits issued in 2011 associated with the Unit 1 fire outage. This increase was offset by a corresponding increase in Retail Margins as discussed above.
  - A $6 million increase associated with the favorable resolution of a contingency in 2011.
  - A $4 million increase in storm restoration expenses.
  - A $3 million increase in customer service costs primarily due to higher DSM expenses. The increase in DSM expenses was offset by a corresponding increase in Retail Margins as discussed above.
- Depreciation and Amortization expenses increased $9 million primarily due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life as approved in the Michigan base case settlement effective April 2012. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
- Income Tax Expense decreased $24 million primarily due to a decrease in pretax book income, other book/tax differences which are accounted for on a flow through basis, the regulatory accounting treatment of state income taxes and federal income tax adjustments recorded in 2011 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 Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2011 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 Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 207 for a discussion of accounting pronouncements.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$499,078	$494,860	$1,371,070	$1,371,349
Sales to AEP Affiliates	71,324	83,417	192,967	229,187
Other Revenues - Affiliated	27,034	29,230	86,797	81,694
Other Revenues - Nonaffiliated	768	3,725	4,453	10,972
TOTAL REVENUES	598,204	611,232	1,655,287	1,693,202
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	137,960	135,927	347,045	359,311
Purchased Electricity for Resale	23,399	25,671	88,797	86,759
Purchased Electricity from AEP Affiliates	110,891	112,416	281,032	274,967
Other Operation	141,728	133,327	411,218	399,384
Maintenance	44,308	50,341	133,817	148,877
Depreciation and Amortization	37,734	33,214	109,273	100,564
Taxes Other Than Income Taxes	21,698	19,984	62,491	62,643
TOTAL EXPENSES	517,718	510,880	1,433,673	1,432,505
OPERATING INCOME	80,486	100,352	221,614	260,697
Other Income (Expense):				
Other Income	2,049	3,944	9,159	11,306
Interest Expense	(26,307)	(24,056)	(76,733)	(73,440)
INCOME BEFORE INCOME TAX EXPENSE	56,228	80,240	154,040	198,563
Income Tax Expense	16,974	28,538	45,755	70,048
NET INCOME	39,254	51,702	108,285	128,515
Preferred Stock Dividend Requirements	-	85	-	255
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$39,254	$51,617	$108,285	$128,260

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Net Income	$ 39,254	$ 51,702	$ 108,285	$ 128,515
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $217 and $2,633 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $2,897 and $2,063 for the Nine Months Ended September 30, 2012 and 2011, Respectively	(404)	(4,891)	(5,381)	(3,832)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $150 and $128 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $450 and $383 for the Nine Months Ended September 30, 2012 and 2011, Respectively	278	238	835	711
TOTAL OTHER COMPREHENSIVE LOSS	(126)	(4,653)	(4,546)	(3,121)
TOTAL COMPREHENSIVE INCOME	$ 39,128	$ 47,049	$ 103,739	$ 125,394

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Net Income			128,515		128,515
Other Comprehensive Loss				(3,121)	(3,121)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$56,584	$981,294	$749,370	$ (24,010)	$1,763,238
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$56,584	$980,896	$751,721	$ (28,221)	$1,760,980
Common Stock Dividends			(50,000)		(50,000)
Subtotal – Common Shareholder's Equity					1,710,980
Net Income			108,285		108,285
Other Comprehensive Loss				(4,546)	(4,546)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2012	$56,584	$980,896	$810,006	$ (32,767)	$1,814,719

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2012 and December 31, 2011
(in thousands)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 767	$ 1,020
Advances to Affiliates	284,768	95,714
Accounts Receivable:		
Customers	63,685	72,461
Affiliated Companies	76,472	90,980
Accrued Unbilled Revenues	20,229	14,780
Miscellaneous	13,488	22,685
Allowance for Uncollectible Accounts	(133)	(1,750)
Total Accounts Receivable	173,741	199,156
Fuel	53,587	52,979
Materials and Supplies	165,284	175,924
Risk Management Assets	28,502	32,152
Accrued Tax Benefits	11,413	38,425
Deferred Cook Plant Fire Costs	64,448	63,809
Prepayments and Other Current Assets	60,657	35,395
TOTAL CURRENT ASSETS	843,167	694,574
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,929,486	3,932,472
Transmission	1,272,008	1,224,786
Distribution	1,527,157	1,481,608
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	683,879	709,558
Construction Work in Progress	237,109	236,096
Total Property, Plant and Equipment	7,649,639	7,584,520
Accumulated Depreciation, Depletion and Amortization	3,224,298	3,179,920
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,425,341	4,404,600
OTHER NONCURRENT ASSETS		
Regulatory Assets	581,048	602,979
Spent Nuclear Fuel and Decommissioning Trusts	1,699,691	1,591,732
Long-term Risk Management Assets	26,304	29,362
Deferred Charges and Other Noncurrent Assets	95,026	69,309
TOTAL OTHER NONCURRENT ASSETS	2,402,069	2,293,382
TOTAL ASSETS	$ 7,670,577	$ 7,392,556

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

106

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2012 and December 31, 2011
(dollars in thousands)
(Unaudited)

	2012	2011
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 95,611	$ 113,063
Affiliated Companies	65,865	81,102
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2012 and December 31, 2011 Amounts Include $126,570 and $101,620, Respectively, Related to DCC Fuel)	304,694	279,075
Risk Management Liabilities	33,188	16,980
Customer Deposits	30,570	30,696
Accrued Taxes	43,963	65,233
Accrued Interest	22,372	27,798
Other Current Liabilities	154,827	117,879
TOTAL CURRENT LIABILITIES	751,090	731,826
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,804,936	1,778,600
Long-term Risk Management Liabilities	14,829	18,871
Deferred Income Taxes	983,791	925,712
Regulatory Liabilities and Deferred Investment Tax Credits	974,541	875,202
Asset Retirement Obligations	1,052,773	1,013,122
Deferred Credits and Other Noncurrent Liabilities	273,898	288,243
TOTAL NONCURRENT LIABILITIES	5,104,768	4,899,750
TOTAL LIABILITIES	5,855,858	5,631,576
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
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	980,896	980,896
Retained Earnings	810,006	751,721
Accumulated Other Comprehensive Income (Loss)	(32,767)	(28,221)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,814,719	1,760,980
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,670,577	$ 7,392,556

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

107

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 108,285	$ 128,515
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	109,273	100,564
Deferred Income Taxes	46,365	71,121
Amortization of Incremental Nuclear Refueling Outage Expenses, Net	2,598	13,544
Allowance for Equity Funds Used During Construction	(6,931)	(11,790)
Mark-to-Market of Risk Management Contracts	9,882	9,014
Amortization of Nuclear Fuel	100,435	107,801
Fuel Over/Under-Recovery, Net	2,867	(4,676)
Change in Other Noncurrent Assets	14,214	15,975
Change in Other Noncurrent Liabilities	46,263	24,603
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	25,415	78,062
Fuel, Materials and Supplies	7,315	40,476
Accounts Payable	(75,799)	(50,265)
Accrued Taxes, Net	7,398	74,510
Other Current Assets	(3,368)	2,924
Other Current Liabilities	39,541	24,264
Net Cash Flows from Operating Activities	433,753	624,642
INVESTING ACTIVITIES		
Construction Expenditures	(212,006)	(224,749)
Change in Advances to Affiliates, Net	(189,054)	(134,004)
Purchases of Investment Securities	(744,131)	(870,769)
Sales of Investment Securities	698,567	825,689
Acquisitions of Nuclear Fuel	(12,545)	(103,970)
Other Investing Activities	29,714	35,583
Net Cash Flows Used for Investing Activities	(429,455)	(472,220)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	128,228	76,414
Change in Advances from Affiliates, Net	-	(42,769)
Retirement of Long-term Debt – Nonaffiliated	(78,062)	(122,469)
Principal Payments for Capital Lease Obligations	(4,929)	(6,353)
Dividends Paid on Common Stock	(50,000)	(56,250)
Dividends Paid on Cumulative Preferred Stock	-	(255)
Other Financing Activities	212	53
Net Cash Flows Used for Financing Activities	(4,551)	(151,629)

Net Increase (Decrease) in Cash and Cash Equivalents	(253)	793
Cash and Cash Equivalents at Beginning of Period	1,020	361
Cash and Cash Equivalents at End of Period	$ 767	$ 1,154
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 79,158	$ 76,390
Net Cash Paid (Received) for Income Taxes	(29,089)	(96,339)
Noncash Acquisitions Under Capital Leases	4,993	2,492
Construction Expenditures Included in Current Liabilities as of September 30,	43,334	28,132
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	42,957	46
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement	-	26,802
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	28,057	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

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

The condensed notes to I&M'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 I&M. The footnotes begin on page 150.

	Footnote Reference
Significant Accounting Matters	Note 1
Rate Matters	Note 2
Commitments, Guarantees and Contingencies	Note 3
Benefit Plans	Note 5
Business Segments	Note 6
Derivatives and Hedging	Note 7
Fair Value Measurements	Note 8
Income Taxes	Note 9
Financing Activities	Note 10
Sustainable Cost Reductions	Note 11

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

CSPCo-OPCo Merger

On December 31, 2011, CSPCo merged into OPCo with OPCo being the surviving entity. All prior reported amounts have been recast as if the merger occurred on the first day of the earliest reporting period. All contracts and operations of CSPCo and its subsidiary are now part of OPCo.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause and established a non-bypassable Distribution Investment Rider (DIR) effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the ESP approved a storm damage recovery mechanism which allowed OPCo to defer the majority of the incremental distribution operation and maintenance costs from 2012 storms.

Finally, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the standard service offer (SSO) load with delivery beginning six months after the receipt of ESP and corporate separation orders and extending through December 2014. The PUCO also ordered OPCo to conduct an energy-only auction for a total of 60% of the SSO load with delivery beginning June 2014 through May 2015. In addition, the PUCO ordered OPCo to conduct an energy-only auction for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. Starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load. In September 2012, OPCo and intervenors filed applications with the PUCO for rehearing. Rehearing of this order is pending at the PUCO.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers to the extent that the total incurred capacity costs do not exceed $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. Several parties, including OPCo, requested rehearing of the July 2012 PUCO order, which was upheld by the PUCO in October 2012. In the August 2012 PUCO order which adopted and modified the new ESP, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide $508 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. In August 2012, the Industrial Energy Users-Ohio (IEU) filed a claim before the Supreme Court of Ohio stating, among other things, that OPCo's recovery of its capacity costs is illegal. OPCo and the PUCO filed motions to dismiss IEU's claim. If OPCo is ultimately not permitted to fully collect its deferred capacity costs and ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 2.

Ohio Customer Choice

In OPCo's service territory, various CRES providers are targeting retail customers by offering alternative generation service. As a result, in comparison to the third quarter of 2011 and the first nine months of 2011, OPCo lost approximately $74 million and $186 million, respectively, of gross margin. This reduction in gross margin is partially

offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs and (d) Retail Stability Rider collections from retail distribution customers. As of September 30, 2012, approximately 42% of OPCo's load had switched to CRES providers and approximately 6% of OPCo's load had formally initiated the switching process to a CRES provider for a total of 48%.

Securitization of Regulatory Assets

In August 2012, OPCo filed an application with the PUCO requesting securitization of the Deferred Asset Recovery Rider (DARR) balance. As of September 30, 2012, OPCo's DARR balance was $296 million, including $139 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018 by a non-bypassable rider.

Significantly Excessive Earnings Test

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. In May 2011, the Industrial Energy Users-Ohio and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended refunds for a portion of 2010 earnings. OPCo is required to file its 2011 SEET filing with the PUCO in 2012 on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo. See "Ohio Electric Security Plan Filing" section of Note 2.

Ohio Distribution Base Rate Case

In December 2011, a stipulation was approved by the PUCO which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved by the modified stipulation in the ESP proceeding. Since the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as filed in the ESP proceeding. See the "2011 Ohio Distribution Base Rate Case" section of Note 2.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings in equal monthly installment payments over the period January 2014 to May 2015 without interest. In the event Ormet, a large industrial customer in Ohio, does not pay the deferred billings, the PUCO permitted OPCo to recover the unpaid balance up to $20 million in future rates. To the extent unpaid deferred billings exceed $20 million, it will reduce future net income and cash flows.

Litigation and Environmental Issues

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot 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 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2011 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 150. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 207 for additional discussion of relevant factors.

112

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions of KWhs)			
Retail:				
Residential	4,198	4,166	11,079	11,758
Commercial	3,907	3,914	10,725	10,815
Industrial	4,463	4,840	13,982	14,195
Miscellaneous	27	28	85	91
Total Retail (a)	12,595	12,948	35,871	36,859
Wholesale	4,173	3,743	9,477	9,424
Total KWhs	16,768	16,691	45,348	46,283

(a) Represents energy delivered to distribution customers.

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,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	9	7	1,553	2,241
Normal - Heating (b)	8	8	2,121	2,109
Actual - Cooling (c)	807	783	1,235	1,107
Normal - Cooling (b)	662	653	934	921

(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 2012 Compared to Third Quarter of 2011

Reconciliation of Third Quarter of 2011 to Third Quarter of 2012
Net Income
(in millions)

Third Quarter of 2011	$	128
Changes in Gross Margin:		
Retail Margins		(61)
Off-system Sales		(10)
Transmission Revenues		12
Total Change in Gross Margin		(59)
Changes in Expenses and Other:		
Other Operation and Maintenance		20
Asset Impairments and Other Related Charges		90
Depreciation and Amortization		20
Taxes Other Than Income Taxes		(2)
Carrying Costs Income		(14)
Other Income		(4)
Interest Expense		3
Total Change in Expenses and Other		113
Income Tax Expense		(30)
Third Quarter of 2012	$	152

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 electricity were as follows:

- Retail Margins decreased $61 million primarily due to the following:
  - An $80 million decrease attributable to customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $33 million decrease in capacity settlement revenues under the Interconnection Agreement. This decrease was primarily as a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sporn Unit 5 from the Interconnection Agreement in September 2011.
  - A $10 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the third quarter 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

  These decreases were partially offset by:
  - A $44 million increase in revenues associated with the Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. The majority of these increases have corresponding increases in other expense items below.

- A $13 million decrease in recoverable PJM expenses.

- Margins from Off-system Sales decreased $10 million primarily due to lower market prices, reduced physical sales volumes and lower trading and marketing margins, partially offset by higher PJM capacity revenues.
- Transmission Revenues increased $12 million primarily due to increased transmission revenues from customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers partially 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 $20 million primarily due to the following:
  - A $9 million decrease in plant maintenance expenses at various plants.
  - A $9 million decrease 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 $3 million decrease due to the deferral of capacity-related costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate proceeding.

  These decreases were partially offset by:
  - A $6 million increase related to the third quarter 2012 recording of an obligation to contribute to Ohio Growth Fund as approved by the PUCO in August 2012.
- Asset Impairments and Other Related Charges decreased $90 million due to the third quarter 2011 plant impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
- Depreciation and Amortization expenses decreased $20 million primarily due to the following:
  - A $21 million decrease 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.
  - A $10 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $9 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate proceeding.
  - A $3 million decrease in depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.

  These decreases were partially offset by:
  - A $17 million increase due to shortened depreciable lives for certain generating plants effective December 2011.
  - A $4 million increase in amortization of the Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
- Carrying Costs Income decreased $14 million primarily 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.
- Other Income decreased $4 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.
- Interest Expense decreased $3 million as a result of a net increase in capitalized interest.
- Income Tax Expense increased $30 million primarily due to an increase in pretax book income and state income tax adjustments related to prior year tax returns.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Reconciliation of Nine Months Ended September 30, 2011 to Nine Months Ended September 30, 2012
Net Income
(in millions)

Nine Months Ended September 30, 2011	$	437
Changes in Gross Margin:		
Retail Margins		(247)
Off-system Sales		8
Transmission Revenues		29
Other Revenues		2
Total Change in Gross Margin		(208)
Changes in Expenses and Other:		
Other Operation and Maintenance		99
Asset Impairments and Other Related Charges		90
Depreciation and Amortization		11
Taxes Other Than Income Taxes		(5)
Carrying Costs Income		(28)
Other Income		(4)
Interest Expense		9
Total Change in Expenses and Other		172
Income Tax Expense		3
Nine Months Ended September 30, 2012	$	404

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 electricity were as follows:

- Retail Margins decreased $247 million primarily due to the following:
  - A $204 million decrease attributable to customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $121 million decrease in capacity settlement revenues under the Interconnection Agreement. This decrease was primarily as a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sporn Unit 5 from the Interconnection Agreement in September 2011.
  - An $81 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the third quarter 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
  - A $14 million decrease in weather-related usage primarily due to a 31% decrease in heating degree days.

  These decreases were partially offset by:

- A $94 million increase in revenues associated with the Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. The majority of these increases have corresponding increases in other expense items below.
- A $35 million increase due to the second quarter 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
- A $30 million decrease in recoverable PJM expenses.
- A $14 million increase due to higher sales to Buckeye Power, Inc. to provide backup energy under the Cardinal Station Agreement.

- Margins from Off-system Sales increased $8 million primarily due to higher PJM capacity revenues, partially offset by lower market prices, reduced physical sales volumes and lower trading and marketing margins.

- Transmission Revenues increased $29 million primarily due to increased transmission revenues from 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 $99 million primarily due to the following:
  - A $49 million decrease in plant maintenance expenses at various plants.
  - A $30 million net decrease related to the reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation and the PUCO's August 2012 approval of the June 2012-May 2015 ESP.
  - A $9 million decrease due to the third quarter 2011 write-off of allocated FEED study costs related to the Mountaineer Carbon Capture Project.
  - A $7 million decrease in employee-related expenses.
  - A $3 million decrease as a result of a legal proceeding recorded in second quarter 2011.
  - A $3 million decrease due to the deferral of capacity-related costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate proceeding.

  These decreases were partially offset by:
  - An $11 million gain from the sale of land in January 2011.
  - A $7 million increase in advertising expenses.
  - A $4 million increase due to expenses related to the 2012 sustainable cost reductions.
- Asset Impairments and Other Related Charges decreased $90 million due to the third quarter 2011 plant impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
- Depreciation and Amortization expenses decreased $11 million primarily due to the following:
  - A $29 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $21 million decrease 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.
  - A $13 million decrease in depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.
  - A $9 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate proceeding.

  These decreases were partially offset by:
  - A $49 million increase due to shortened depreciable lives for certain generating plants effective December 2011.
  - A $9 million increase in amortization of the Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased capital investments and increased tax rates.
- Carrying Costs Income decreased $28 million primarily due to the following:
  -

An $11 million decrease 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.

- A $5 million reduction in debt carrying charges associated with the 2008 coal contract settlement for the period January 2009 through March 2012 as ordered by the PUCO in April 2012 related to the 2009 FAC audit.
- A $5 million decrease due to line extension carrying charges recorded in 2011.

- Interest Expense decreased $9 million as a result of a net increase in capitalized interest and the reversal of interest accruals related to federal tax reserve positions.
- Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income partially offset by other book/tax differences which are accounted for on a flow through basis and state 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 Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2011 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 Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 207 for a discussion of accounting pronouncements.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$1,114,339	$1,241,423	$3,084,657	$3,413,128
Sales to AEP Affiliates	229,879	285,010	584,197	773,169
Other Revenues - Affiliated	10,207	9,066	27,297	20,591
Other Revenues - Nonaffiliated	5,391	4,732	14,638	13,091
TOTAL REVENUES	1,359,816	1,540,231	3,710,789	4,219,979
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	426,989	479,938	1,095,276	1,228,067
Purchased Electricity for Resale	46,146	65,834	156,384	203,231
Purchased Electricity from AEP Affiliates	109,453	157,776	279,954	402,121
Other Operation	189,566	202,272	481,994	532,224
Maintenance	73,024	80,587	227,643	276,029
Asset Impairments and Other Related Charges	-	89,824	-	89,824
Depreciation and Amortization	130,026	149,626	401,465	412,736
Taxes Other Than Income Taxes	105,503	103,921	309,341	304,364
TOTAL EXPENSES	1,080,707	1,329,778	2,952,057	3,448,596
OPERATING INCOME	279,109	210,453	758,732	771,383
Other Income (Expense):				
Interest Income	425	4,167	1,868	5,062
Carrying Costs Income	7,132	21,586	14,401	42,164
Allowance for Equity Funds Used During Construction	998	1,413	3,036	4,124
Interest Expense	(53,576)	(56,677)	(160,984)	(170,328)
INCOME BEFORE INCOME TAX EXPENSE	234,088	180,942	617,053	652,405
Income Tax Expense	82,578	52,603	213,290	215,902
NET INCOME	151,510	128,339	403,763	436,503
Preferred Stock Dividend Requirements Including				
Capital Stock Expense	-	208	-	624
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$151,510	$128,131	$403,763	$435,879

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

119

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Net Income	$ 151,510	$ 128,339	$ 403,763	$ 436,503
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $956 and $648 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $111 and $368 for the Nine Months Ended September 30, 2012 and 2011, Respectively	1,776	(1,204)	205	(683)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,745 and $1,577 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $5,234 and $4,421 for the Nine Months Ended September 30, 2012 and 2011, Respectively	3,240	2,929	9,721	8,210
TOTAL OTHER COMPREHENSIVE INCOME	5,016	1,725	9,926	7,527
TOTAL COMPREHENSIVE INCOME	$ 156,526	$ 130,064	$ 413,689	$ 444,030

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$321,201	$1,744,991	$2,768,602	$ (180,155)	$4,654,639
Common Stock Dividends			(487,500)		(487,500)
Preferred Stock Dividends			(549)		(549)
Capital Stock Expense		75	(75)		-
Subtotal – Common Shareholder's Equity					4,166,590
Net Income			436,503		436,503
Other Comprehensive Income				7,527	7,527
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$321,201	$1,745,066	$2,716,981	$ (172,628)	$4,610,620
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$321,201	$1,744,099	$2,582,600	$ (197,722)	$4,450,178
Common Stock Dividends			(225,000)		(225,000)
Subtotal – Common Shareholder's Equity					4,225,178
Net Income			403,763		403,763
Other Comprehensive Income				9,926	9,926
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2012	$321,201	$1,744,099	$2,761,363	$ (187,796)	$4,638,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2012 and December 31, 2011
(in thousands)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,930	$ 2,095
Advances to Affiliates	124,606	219,458
Accounts Receivable:		
Customers	103,211	146,432
Affiliated Companies	150,978	162,830
Accrued Unbilled Revenues	51,967	19,012
Miscellaneous	6,391	16,994
Allowance for Uncollectible Accounts	(26)	(3,563)
Total Accounts Receivable	312,521	341,705
Fuel	325,330	262,886
Materials and Supplies	187,899	201,325
Risk Management Assets	44,704	54,293
Accrued Tax Benefits	1,512	11,975
Prepayments and Other Current Assets	33,276	41,560
TOTAL CURRENT ASSETS	1,031,778	1,135,297
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	9,608,241	9,502,614
Transmission	1,986,600	1,948,329
Distribution	3,690,824	3,545,574
Other Property, Plant and Equipment	585,349	546,642
Construction Work in Progress	318,092	354,465
Total Property, Plant and Equipment	16,189,106	15,897,624
Accumulated Depreciation and Amortization	5,894,263	5,742,561
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,294,843	10,155,063
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,455,396	1,370,504
Long-term Risk Management Assets	54,327	53,614
Deferred Charges and Other Noncurrent Assets	140,166	309,775
TOTAL OTHER NONCURRENT ASSETS	1,649,889	1,733,893
TOTAL ASSETS	$ 12,976,510	$ 13,024,253

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2012 and December 31, 2011
(Unaudited)

	2012	2011
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 233,017	$ 293,730
Affiliated Companies	101,268	183,898
Long-term Debt Due Within One Year – Nonaffiliated	856,000	244,500
Risk Management Liabilities	26,658	36,561
Accrued Taxes	249,301	450,570
Accrued Interest	66,973	66,441
Other Current Liabilities	267,814	238,275
TOTAL CURRENT LIABILITIES	1,801,031	1,513,975
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,804,242	3,609,648
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	29,513	17,890
Deferred Income Taxes	2,398,292	2,245,380
Regulatory Liabilities and Deferred Investment Tax Credits	475,437	301,124
Employee Benefits and Pension Obligations	299,560	335,029
Deferred Credits and Other Noncurrent Liabilities	329,568	351,029
TOTAL NONCURRENT LIABILITIES	6,536,612	7,060,100
TOTAL LIABILITIES	8,337,643	8,574,075
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,744,099	1,744,099
Retained Earnings	2,761,363	2,582,600
Accumulated Other Comprehensive Income (Loss)	(187,796)	(197,722)
TOTAL COMMON SHAREHOLDER’S EQUITY	4,638,867	4,450,178
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,976,510	$ 13,024,253

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 403,763	$ 436,503
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	401,465	412,736
Deferred Income Taxes	126,009	117,803
Asset Impairments and Other Related Charges	-	89,824
Carrying Costs Income	(14,401)	(42,164)
Allowance for Equity Funds Used During Construction	(3,036)	(4,124)
Mark-to-Market of Risk Management Contracts	12,420	14,548
Property Taxes	164,496	160,466
Fuel Over/Under-Recovery, Net	4,766	(41,989)
Change in Other Noncurrent Assets	(77,310)	(60,179)
Change in Other Noncurrent Liabilities	(11,019)	19,110
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	29,255	126,873
Fuel, Materials and Supplies	(46,712)	129,232
Accounts Payable	(135,419)	(77,427)
Accrued Taxes, Net	(161,613)	(197,378)
Other Current Assets	2,599	12,711
Other Current Liabilities	(3,639)	(28,093)
Net Cash Flows from Operating Activities	691,624	1,068,452
INVESTING ACTIVITIES		
Construction Expenditures	(374,417)	(299,854)
Change in Advances to Affiliates, Net	94,852	(225,426)
Acquisitions of Assets	(116)	(1,734)
Proceeds from Sales of Assets	6,226	47,075
Other Investing Activities	8,642	26,013
Net Cash Flows Used for Investing Activities	(264,813)	(453,926)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	49,757
Retirement of Long-term Debt – Nonaffiliated	(194,500)	(165,000)
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(7,678)	(8,956)
Dividends Paid on Common Stock	(225,000)	(487,500)
Dividends Paid on Cumulative Preferred Stock	-	(549)
Other Financing Activities	202	18
Net Cash Flows Used for Financing Activities	(426,976)	(612,232)
Net Increase (Decrease) in Cash and Cash Equivalents	(165)	2,294

Cash and Cash Equivalents at Beginning of Period		2,095		949
Cash and Cash Equivalents at End of Period	$	1,930	$	3,243
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	157,944	$	165,600
Net Cash Paid for Income Taxes		33,400		103,310
Noncash Acquisitions Under Capital Leases		5,658		2,198
Government Grants Included in Accounts Receivable as of September 30,		585		1,539
Construction Expenditures Included in Current Liabilities as of September 30,		56,357		46,138

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

OHIO POWER COMPANY CONSOLIDATED
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to OPCo'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 OPCo. The footnotes begin on page 150.

	Footnote Reference
Significant Accounting Matters	Note 1
Rate Matters	Note 2
Commitments, Guarantees and Contingencies	Note 3
Acquisition and Impairments	Note 4
Benefit Plans	Note 5
Business Segments	Note 6
Derivatives and Hedging	Note 7
Fair Value Measurements	Note 8
Income Taxes	Note 9
Financing Activities	Note 10
Sustainable Cost Reductions	Note 11

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Litigation and Environmental Issues

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot 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 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2011 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 150. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 207 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,	
	2012	2011	2012	2011
	(in millions of KWhs)			
Retail:				
Residential	2,332	2,423	5,211	5,500
Commercial	1,518	1,476	3,992	3,996
Industrial	1,346	1,378	3,837	3,743
Miscellaneous	383	390	1,025	1,007
Total Retail (a)	5,579	5,667	14,065	14,246
Wholesale	334	314	1,273	866
Total KWhs	5,913	5,981	15,338	15,112

(a) Represents energy delivered to distribution customers.

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,

	2012	2011	2012	2011
			(in degree days)	
Actual - Heating (a)	-	-	676	1,276
Normal - Heating (b)	2	2	1,109	1,102
Actual - Cooling (c)	1,622	1,749	2,557	2,694
Normal - Cooling (b)	1,398	1,391	2,046	2,028

(a) 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) Western Region cooling degree days are calculated on a 65 degree temperature base.

Third Quarter of 2012 Compared to Third Quarter of 2011

Reconciliation of Third Quarter of 2011 to Third Quarter of 2012
Net Income
(in millions)

Third Quarter of 2011	$	57
Changes in Gross Margin:		
Retail Margins (a)		(1)
Off-system Sales		(1)
Other Revenues		(1)
Total Change in Gross Margin		(3)
Changes in Expenses and Other:		
Other Operation and Maintenance		5
Taxes Other Than Income Taxes		1
Total Change in Expenses and Other		6
Income Tax Expense		(2)
Third Quarter of 2012	$	58

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

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 electricity were as follows:

- Retail Margins decreased $1 million primarily due to the following:
  - A $5 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days.

  This decrease was partially offset by:
  - A $2 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $5 million primarily due to the following:
  - A $5 million decrease in generation plant maintenance expenses.
  - A $3 million decrease in distribution maintenance expenses primarily due to decreased vegetation management expenses.
  - A $2 million decrease in demand side management programs.

  These decreases were partially offset by:
  - A $5 million increase in transmission expenses primarily due to increased SPP transmission services.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Reconciliation of Nine Months Ended September 30, 2011 to Nine Months Ended September 30, 2012
Net Income
(in millions)

Nine Months Ended September 30, 2011	$	104
Changes in Gross Margin:		
Retail Margins (a)		8
Off-system Sales		(1)
Transmission Revenues		(2)
Other Revenues		1
Total Change in Gross Margin		6
Changes in Expenses and Other:		
Other Operation and Maintenance		(4)
Depreciation and Amortization		1
Interest Expense		2
Total Change in Expenses and Other		(1)
Income Tax Expense		(3)
Nine Months Ended September 30, 2012	$	106

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

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 electricity were as follows:

- Retail Margins increased $8 million primarily due to the following:
  - An $11 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.
  - A $9 million increase primarily due to higher commercial and residential non-weather related usage.

  These increases were partially offset by:
  - A $13 million decrease in weather-related usage primarily due to a 47% decrease in heating degree days and a 5% decrease in cooling degree days.

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

- Other Operation and Maintenance expenses increased $4 million primarily due to the following:
  - A $12 million increase in transmission expenses primarily due to increased SPP transmission services.

  This increase was partially offset by:
  - A $7 million decrease in general and administrative expenses.
  -

A $2 million decrease in distribution expenses primarily due to decreased overhead line expense.

- Income Tax Expense increased $3 million primarily due to an increase in pretax book income and state income taxes.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2011 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 Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 207 for a discussion of accounting pronouncements.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$364,851	$454,802	$968,683	$1,061,417
Sales to AEP Affiliates	6,865	2,115	19,377	10,696
Other Revenues	1,156	669	2,654	2,064
TOTAL REVENUES	372,872	457,586	990,714	1,074,177
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	65,195	168,230	281,746	360,774
Purchased Electricity for Resale	75,719	42,455	145,983	129,652
Purchased Electricity from AEP Affiliates	5,870	17,477	16,328	43,199
Other Operation	58,975	58,225	154,834	151,365
Maintenance	25,685	31,892	78,863	77,765
Depreciation and Amortization	24,433	24,802	71,356	72,761
Taxes Other Than Income Taxes	10,799	11,499	32,619	32,589
TOTAL EXPENSES	266,676	354,580	781,729	868,105
OPERATING INCOME	106,196	103,006	208,985	206,072
Other Income (Expense):				
Interest Income	171	164	1,203	244
Carrying Costs Income	418	810	1,560	3,333
Allowance for Equity Funds Used During Construction	408	189	1,298	839
Interest Expense	(13,735)	(13,831)	(42,212)	(44,027)
INCOME BEFORE INCOME TAX EXPENSE	93,458	90,338	170,834	166,461
Income Tax Expense	35,355	32,989	64,872	62,163
NET INCOME	58,103	57,349	105,962	104,298
Preferred Stock Dividend Requirements	-	49	-	147
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$58,103	$57,300	$105,962	$104,151

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Net Income	$ 58,103	$ 57,349	$ 105,962	$ 104,298
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $28 and $233 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $250 and $640 for the Nine Months Ended September 30, 2012 and 2011, Respectively	(53)	(432)	(465)	(1,188)
TOTAL COMPREHENSIVE INCOME	$ 58,050	$ 56,917	$ 105,497	$ 103,110

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$157,230	$364,307	$312,441	$ 8,494	$842,472
Common Stock Dividends			(52,500)		(52,500)
Preferred Stock Dividends			(147)		(147)
Subtotal – Common Shareholder's Equity					789,825
Net Income			104,298		104,298
Other Comprehensive Loss				(1,188)	(1,188)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$157,230	$364,307	$364,092	$ 7,306	$892,935
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$157,230	$364,037	$364,389	$ 7,149	$892,805
Common Stock Dividends			(60,000)		(60,000)
Subtotal – Common Shareholder's Equity					832,805
Net Income			105,962		105,962
Other Comprehensive Loss				(465)	(465)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2012	$157,230	$364,037	$410,351	$ 6,684	$938,302

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2012 and December 31, 2011
(in thousands)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,022	$ 1,413
Advances to Affiliates	107,459	39,876
Accounts Receivable:		
Customers	30,220	39,977
Affiliated Companies	27,952	23,079
Miscellaneous	3,688	8,993
Allowance for Uncollectible Accounts	(1,179)	(777)
Total Accounts Receivable	60,681	71,272
Fuel	21,820	20,854
Materials and Supplies	51,701	50,347
Risk Management Assets	545	565
Deferred Income Tax Benefits	9,925	7,013
Accrued Tax Benefits	7,714	6,733
Regulatory Asset for Under-Recovered Fuel Costs	-	4,313
Prepayments and Other Current Assets	8,030	6,440
TOTAL CURRENT ASSETS	268,897	208,826
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,335,087	1,317,948
Transmission	702,696	692,644
Distribution	1,836,835	1,762,110
Other Property, Plant and Equipment	228,234	214,626
Construction Work in Progress	69,842	70,371
Total Property, Plant and Equipment	4,172,694	4,057,699
Accumulated Depreciation and Amortization	1,290,823	1,266,816
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,881,871	2,790,883
OTHER NONCURRENT ASSETS		
Regulatory Assets	241,984	266,545
Long-term Risk Management Assets	124	314
Deferred Charges and Other Noncurrent Assets	18,824	13,536
TOTAL OTHER NONCURRENT ASSETS	260,932	280,395
TOTAL ASSETS	$ 3,411,700	$ 3,280,104

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2012 and December 31, 2011
(Unaudited)

	2012	2011
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 83,313	$ 76,607
Affiliated Companies	22,996	45,029
Long-term Debt Due Within One Year – Nonaffiliated	761	311
Risk Management Liabilities	5,071	1,280
Customer Deposits	46,577	47,493
Accrued Taxes	59,612	21,660
Accrued Interest	15,350	12,637
Regulatory Liability for Over-Recovered Fuel Costs	35,927	-
Other Current Liabilities	39,434	43,586
TOTAL CURRENT LIABILITIES	309,041	248,603
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	949,123	947,053
Long-term Risk Management Liabilities	1,051	1,330
Deferred Income Taxes	754,313	726,463
Regulatory Liabilities and Deferred Investment Tax Credits	343,276	334,812
Employee Benefits and Pension Obligations	74,551	84,548
Deferred Credits and Other Noncurrent Liabilities	42,043	44,490
TOTAL NONCURRENT LIABILITIES	2,164,357	2,138,696
TOTAL LIABILITIES	2,473,398	2,387,299
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	364,037	364,037
Retained Earnings	410,351	364,389
Accumulated Other Comprehensive Income (Loss)	6,684	7,149
TOTAL COMMON SHAREHOLDER’S EQUITY	938,302	892,805
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 3,411,700	$ 3,280,104

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

134

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 105,962	$ 104,298
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	71,356	72,761
Deferred Income Taxes	22,524	45,927
Carrying Costs Income	(1,560)	(3,333)
Allowance for Equity Funds Used During Construction	(1,298)	(839)
Mark-to-Market of Risk Management Contracts	3,868	(2,226)
Fuel Over/Under-Recovery, Net	40,240	4,389
Change in Other Noncurrent Assets	1,196	4,326
Change in Other Noncurrent Liabilities	(1,325)	22,794
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	10,684	53,995
Fuel, Materials and Supplies	(2,320)	468
Accounts Payable	(11,632)	3,506
Accrued Taxes, Net	43,313	63,993
Other Current Assets	(1,864)	(3,839)
Other Current Liabilities	(1,275)	11,593
Net Cash Flows from Operating Activities	277,869	377,813
INVESTING ACTIVITIES		
Construction Expenditures	(151,603)	(97,038)
Change in Advances to Affiliates, Net	(67,583)	(105,116)
Other Investing Activities	1,107	782
Net Cash Flows Used for Investing Activities	(218,079)	(201,372)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	2,395	247,481
Change in Advances from Affiliates, Net	-	(91,382)
Retirement of Long-term Debt – Nonaffiliated	(130)	(275,000)
Principal Payments for Capital Lease Obligations	(2,585)	(3,103)
Dividends Paid on Common Stock	(60,000)	(52,500)
Dividends Paid on Cumulative Preferred Stock	-	(147)
Other Financing Activities	139	13
Net Cash Flows Used for Financing Activities	(60,181)	(174,638)
Net Increase (Decrease) in Cash and Cash Equivalents	(391)	1,803
Cash and Cash Equivalents at Beginning of Period	1,413	470
Cash and Cash Equivalents at End of Period	$ 1,022	$ 2,273
SUPPLEMENTARY INFORMATION		

Cash Paid for Interest, Net of Capitalized Amounts	$ 36,681	$ 23,397
Net Cash Paid (Received) for Income Taxes	17,988	(26,536)
Noncash Acquisitions Under Capital Leases	979	634
Construction Expenditures Included in Current Liabilities as of September 30,	23,872	13,400

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to PSO'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 PSO. The footnotes begin on page 150.

	Footnote Reference
Significant Accounting Matters	Note 1
Rate Matters	Note 2
Commitments, Guarantees and Contingencies	Note 3
Benefit Plans	Note 5
Business Segments	Note 6
Derivatives and Hedging	Note 7
Fair Value Measurements	Note 8
Income Taxes	Note 9
Financing Activities	Note 10
Sustainable Cost Reductions	Note 11

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

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 scheduled to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. See "Turk Plant" section of Note 2.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operations and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. A decision from the PUCT is expected in the second quarter of 2013. See "2012 Texas Base Rate Case" section of Note 2.

Litigation and Environmental Issues

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot 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 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies in the 2011 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 150. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 207 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,	
	2012	2011	2012	2011
	(in millions of KWhs)			
Retail:				
Residential	2,120	2,372	5,072	5,621
Commercial	1,764	1,831	4,718	4,861
Industrial	1,448	1,372	4,279	4,049

Miscellaneous	20	19	60	61
Total Retail (a)	5,352	5,594	14,129	14,592
Wholesale	2,108	2,410	5,987	6,074
Total KWhs	7,460	8,004	20,116	20,666

(a) Represents energy delivered to distribution customers.

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,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	-	-	427	866
Normal - Heating (b)	1	1	774	774
Actual - Cooling (c)	1,457	1,732	2,481	2,717
Normal - Cooling (b)	1,396	1,381	2,136	2,112

(a) 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) Western Region cooling degree days are calculated on a 65 degree temperature base.

Third Quarter of 2012 Compared to Third Quarter of 2011

Reconciliation of Third Quarter of 2011 to Third Quarter of 2012
Net Income
(in millions)

Third Quarter of 2011	$	88
Changes in Gross Margin:		
Retail Margins (a)		(9)
Other Revenues		(1)
Total Change in Gross Margin		(10)
Changes in Expenses and Other:		
Other Operation and Maintenance		6
Depreciation and Amortization		(1)
Taxes Other Than Income Taxes		(4)
Interest Income		(1)
Allowance for Equity Funds Used During Construction		3
Interest Expense		(1)
Total Change in Expenses and Other		2
Income Tax Expense		9
Third Quarter of 2012	$	89

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

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 electricity were as follows:

- Retail Margins decreased $9 million primarily due to the following:
  - A $15 million decrease in weather-related usage primarily due to a 16% decrease in cooling degree days.
  - An $8 million decrease primarily due to wholesale fuel recovery adjustments.

  These decreases were partially offset by:
  - A $7 million increase in municipal and cooperative revenues due to higher rates and formula rate adjustments.
  - A $7 million increase in retail revenues due to higher rates.

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

- Other Operation and Maintenance expenses decreased $6 million primarily due to the following:
  - A $2 million decrease in generation plant maintenance expenses.
  - A $2 million decrease related to 2011 litigation expenses.
- Taxes Other Than Income Taxes increased $4 million primarily due to favorable property tax adjustments made in the third quarter of 2011.

- Allowance for Equity Funds Used During Construction increased $3 million primarily due to construction at the Turk Plant.
- Income Tax Expense decreased $9 million primarily due to a decrease in pretax book income, the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Reconciliation of Nine Months Ended September 30, 2011 to Nine Months Ended September 30, 2012
Net Income
(in millions)

Nine Months Ended September 30, 2011	$	169
Changes in Gross Margin:		
Retail Margins (a)		(14)
Off-system Sales		1
Transmission Revenues		2
Other Revenues		(1)
Total Change in Gross Margin		(12)
Changes in Expenses and Other:		
Other Operation and Maintenance		19
Asset Impairment and Other Related Charges		(13)
Depreciation and Amortization		(4)
Taxes Other Than Income Taxes		(4)
Allowance for Equity Funds Used During Construction		8
Interest Expense		(1)
Total Change in Expenses and Other		5
Income Tax Expense		19
Nine Months Ended September 30, 2012	$	181

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

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 electricity were as follows:

- Retail Margins decreased $14 million primarily due to the following:
  - A $22 million decrease in weather-related usage primarily due to a 51% decrease in heating degree days and a 9% decrease in cooling degree days.
  - A $13 million decrease primarily due to fuel expense adjustments.

  These decreases were partially offset by:
  - A $16 million increase in municipal and cooperative revenues due to higher rates and formula rate adjustments.
  - A $5 million increase in retail revenues due to higher rates.

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

- Other Operation and Maintenance expenses decreased $19 million primarily due to the following:

- An $11 million decrease in generation maintenance expenses primarily due to higher 2011 planned and unplanned plant outages.
- A $5 million decrease related to 2011 litigation expenses.
- A $3 million decrease in distribution maintenance expenses primarily due to decreased vegetation management and storm-related expenses.

- Asset Impairment and Other Related Charges includes the 2012 write-off of $13 million related to the expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.
- Depreciation and Amortization expenses increased $4 million primarily due to a greater depreciable base.
- Taxes Other Than Income Taxes increased $4 million primarily due to favorable property tax adjustments made in the third quarter of 2011.

- Allowance for Equity Funds Used During Construction increased $8 million primarily due to construction at the Turk Plant.
- Income Tax Expense decreased $19 million primarily due to a decrease in pretax book income, the regulatory accounting treatment of state income taxes and 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 Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2011 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 Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 207 for a discussion of accounting pronouncements.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$473,391	$512,767	$1,196,753	$1,248,031
Sales to AEP Affiliates	11,098	21,618	26,945	47,868
Other Revenues	680	597	1,403	1,572
TOTAL REVENUES	485,169	534,982	1,225,101	1,297,471
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	180,991	213,004	447,233	486,729
Purchased Electricity for Resale	35,109	47,241	97,150	125,521
Purchased Electricity from AEP Affiliates	6,121	1,880	16,965	9,107
Other Operation	60,217	63,655	165,877	168,445
Maintenance	27,816	30,895	78,835	95,076
Asset Impairment and Other Related Charges	-	-	13,000	-
Depreciation and Amortization	35,144	33,919	103,820	99,927
Taxes Other Than Income Taxes	19,763	15,982	53,869	49,678
TOTAL EXPENSES	365,161	406,576	976,749	1,034,483
OPERATING INCOME	120,008	128,406	248,352	262,988
Other Income (Expense):				
Interest Income	39	1,070	1,171	1,181
Allowance for Equity Funds Used During Construction	15,216	12,692	43,401	34,861
Interest Expense	(21,498)	(20,964)	(65,210)	(64,224)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	113,765	121,204	227,714	234,806
Income Tax Expense	25,229	34,217	49,206	68,184
Equity Earnings of Unconsolidated Subsidiary	682	808	2,007	2,071
NET INCOME	89,218	87,795	180,515	168,693
Net Income Attributable to Noncontrolling Interest	955	1,023	3,099	3,141
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	88,263	86,772	177,416	165,552
Preferred Stock Dividend Requirements	-	58	-	172
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$88,263	$86,714	$177,416	$165,380

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Net Income	$89,218	$87,795	$180,515	$168,693
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $376 and $5,332 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $367 and $5,195 for the Nine Months Ended September 30, 2012 and 2011, Respectively	697	(9,903)	(682)	(9,648)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $90 and $475 for the Three Months Ended September 30, 2012 and 2011, Respectively, and $269 and $206 for the Nine Months Ended September 30, 2012 and 2011, Respectively	167	(882)	499	383
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	864	(10,785)	(183)	(9,265)
TOTAL COMPREHENSIVE INCOME	90,082	77,010	180,332	159,428
Total Comprehensive Income Attributable to Noncontrolling Interest	955	1,023	3,099	3,141
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	$89,127	$75,987	$177,233	$156,287

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2010	$135,660	$674,979	$868,840	$ (12,491)	$ 361	$1,667,349
Common Stock Dividends – Nonaffiliated					(3,183)	(3,183)
Preferred Stock Dividends			(172)			(172)
Subtotal – Equity						1,663,994
Net Income			165,552		3,141	168,693
Other Comprehensive Loss				(9,265)		(9,265)
TOTAL EQUITY – SEPTEMBER 30, 2011	$135,660	$674,979	$1,034,220	$ (21,756)	$ 319	$1,823,422
TOTAL EQUITY – DECEMBER 31, 2011	$135,660	$674,606	$1,029,915	$ (26,815)	$ 391	$1,813,757
Common Stock Dividends – Nonaffiliated					(3,176)	(3,176)
Subtotal – Equity						1,810,581
Net Income			177,416		3,099	180,515
Other Comprehensive Loss				(183)		(183)
TOTAL EQUITY – SEPTEMBER 30, 2012	$135,660	$674,606	$1,207,331	$ (26,998)	$ 314	$1,990,913

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2012 and December 31, 2011
(in thousands)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents		
(September 30, 2012 Amount Includes $14,926 Related to Sabine)	$ 16,626	$ 801
Advances to Affiliates	128,227	-
Accounts Receivable:		
Customers	37,366	35,054
Affiliated Companies	18,607	23,730
Miscellaneous	37,973	19,370
Allowance for Uncollectible Accounts	(1,685)	(989)
Total Accounts Receivable	92,261	77,165
Fuel		
(September 30, 2012 and December 31, 2011 Amounts Include $24,229 and $32,651, Respectively, Related to Sabine)	112,278	102,015
Materials and Supplies	72,973	55,325
Risk Management Assets	705	445
Deferred Income Tax Benefits	6,664	8,195
Accrued Tax Benefits	38,376	1,541
Regulatory Asset for Under-Recovered Fuel Costs	8,382	10,843
Prepayments and Other Current Assets	23,657	16,827
TOTAL CURRENT ASSETS	500,149	273,157
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,337,734	2,326,102
Transmission	1,102,142	988,534
Distribution	1,744,173	1,675,764
Other Property, Plant and Equipment		
(September 30, 2012 and December 31, 2011 Amounts Include $256,492 and $232,948, Respectively, Related to Sabine)	675,694	637,019
Construction Work in Progress	1,583,826	1,443,569
Total Property, Plant and Equipment	7,443,569	7,070,988
Accumulated Depreciation and Amortization		
(September 30, 2012 and December 31, 2011 Amounts Include $112,275 and $103,586, Respectively, Related to Sabine)	2,282,762	2,211,912
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,160,807	4,859,076

OTHER NONCURRENT ASSETS				
Regulatory Assets		430,013		394,276
Long-term Risk Management Assets		178		282
Deferred Charges and Other Noncurrent Assets		89,080		74,992
TOTAL OTHER NONCURRENT ASSETS		519,271		469,550
TOTAL ASSETS	$	6,180,227	$	5,601,783

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2012 and December 31, 2011
(Unaudited)

	2012	2011
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 132,473
Accounts Payable:		
General	149,583	181,268
Affiliated Companies	40,076	59,201
Short-term Debt – Nonaffiliated	-	17,016
Long-term Debt Due Within One Year – Nonaffiliated	3,250	20,000
Risk Management Liabilities	4,148	24,359
Customer Deposits	53,187	52,095
Accrued Taxes	53,188	44,404
Accrued Interest	19,182	39,629
Obligations Under Capital Leases	17,426	15,058
Regulatory Liability for Over-Recovered Fuel Costs	13,000	5,032
Other Current Liabilities	65,615	64,413
TOTAL CURRENT LIABILITIES	418,655	654,948
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,042,889	1,708,637
Long-term Risk Management Liabilities	134	221
Deferred Income Taxes	926,183	665,668
Regulatory Liabilities and Deferred Investment Tax Credits	469,652	428,571
Asset Retirement Obligations	80,359	65,673
Employee Benefits and Pension Obligations	81,257	87,159
Obligations Under Capital Leases	116,750	112,802
Deferred Credits and Other Noncurrent Liabilities	53,435	64,347
TOTAL NONCURRENT LIABILITIES	3,770,659	3,133,078
TOTAL LIABILITIES	4,189,314	3,788,026
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	674,606	674,606
Retained Earnings	1,207,331	1,029,915
Accumulated Other Comprehensive Income (Loss)	(26,998)	(26,815)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,990,599	1,813,366

Noncontrolling Interest		314		391
TOTAL EQUITY		1,990,913		1,813,757
TOTAL LIABILITIES AND EQUITY	$	6,180,227	$	5,601,783

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2012 and 2011
(in thousands)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 180,515	$ 168,693
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	103,820	99,927
Deferred Income Taxes	215,283	36,979
Asset Impairment and Other Related Charges	13,000	-
Allowance for Equity Funds Used During Construction	(43,401)	(34,861)
Mark-to-Market of Risk Management Contracts	(1,179)	(3,148)
Fuel Over/Under-Recovery, Net	10,429	(30,259)
Change in Other Noncurrent Assets	2,355	19,606
Change in Other Noncurrent Liabilities	25,945	32,685
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(15,071)	9,718
Fuel, Materials and Supplies	(27,911)	(10,508)
Accounts Payable	(13,474)	2,906
Accrued Taxes, Net	(24,649)	68,674
Accrued Interest	(20,473)	(22,240)
Other Current Assets	(7,940)	(3,356)
Other Current Liabilities	(12,570)	(2,545)
Net Cash Flows from Operating Activities	384,679	332,271
INVESTING ACTIVITIES		
Construction Expenditures	(395,829)	(395,193)
Change in Advances to Affiliates, Net	(128,227)	86,222
Other Investing Activities	1,240	(3,479)
Net Cash Flows Used for Investing Activities	(522,816)	(312,450)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	336,429	-
Credit Facility Borrowings	21,462	32,532
Change in Advances from Affiliates, Net	(132,473)	41,537
Retirement of Long-term Debt – Nonaffiliated	(21,625)	(41,135)
Retirement of Cumulative Preferred Stock	-	(2)
Credit Facility Repayments	(38,478)	(38,749)
Principal Payments for Capital Lease Obligations	(12,036)	(10,029)
Dividends Paid on Common Stock – Nonaffiliated	(3,176)	(3,183)
Dividends Paid on Cumulative Preferred Stock	-	(172)
Other Financing Activities	3,859	3,650
Net Cash Flows from (Used for) Financing Activities	153,962	(15,551)

Net Increase in Cash and Cash Equivalents		15,825		4,270
Cash and Cash Equivalents at Beginning of Period		801		1,514
Cash and Cash Equivalents at End of Period	$	16,626	$	5,784
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	74,656	$	78,239
Net Cash Paid (Received) for Income Taxes		(112,290)		(8,586)
Noncash Acquisitions Under Capital Leases		18,560		10,296
Construction Expenditures Included in Current Liabilities at September 30,		72,318		99,600

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 150.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to SWEPCo'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 SWEPCo. The footnotes begin on page 150.

	Footnote Reference
Significant Accounting Matters	Note 1
Rate Matters	Note 2
Commitments, Guarantees and Contingencies	Note 3
Acquisition and Impairments	Note 4
Benefit Plans	Note 5
Business Segments	Note 6
Derivatives and Hedging	Note 7
Fair Value Measurements	Note 8
Income Taxes	Note 9
Financing Activities	Note 10
Sustainable Cost Reductions	Note 11

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	APCo, I&M, OPCo, PSO, SWEPCo
2.	Rate Matters	APCo, I&M, OPCo, PSO, SWEPCo
3.	Commitments, Guarantees and Contingencies	APCo, I&M, OPCo, PSO, SWEPCo
4.	Acquisition and Impairments	APCo, OPCo, SWEPCo
5.	Benefit Plans	APCo, I&M, OPCo, PSO, SWEPCo
6.	Business Segments	APCo, I&M, OPCo, PSO, SWEPCo
7.	Derivatives and Hedging	APCo, I&M, OPCo, PSO, SWEPCo
8.	Fair Value Measurements	APCo, I&M, OPCo, PSO, SWEPCo
9.	Income Taxes	APCo, I&M, OPCo, PSO, SWEPCo
10.	Financing Activities	APCo, I&M, OPCo, PSO, SWEPCo
11.	Sustainable Cost Reductions	APCo, I&M, OPCo, PSO, SWEPCo

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed 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 interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. Net income for the three and nine months ended September 30, 2012 is not necessarily indicative of results that may be expected for the year ending December 31, 2012. The condensed financial statements are unaudited and should be read in conjunction with the audited 2011 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2011 as filed with the SEC on February 28, 2012.

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 they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. APCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and OPCo each hold a significant variable interest in AEGCo. SWEPCo holds a significant variable interest in DHLC.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined 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, 2012 and 2011 were $35 million and $33 million, respectively, and for the nine months ended September 30, 2012 and 2011 were $126 million and $97 million, respectively. See the table below for the classification of Sabine's assets and liabilities on SWEPCo's condensed balance sheets.

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
September 30, 2012 and December 31, 2011
(in thousands)

	Sabine	
ASSETS	2012	2011
Current Assets	$ 71,026	$ 48,044
Net Property, Plant and Equipment	174,743	153,715
Other Noncurrent Assets	56,687	42,574
Total Assets	$ 302,456	$ 244,333
LIABILITIES AND EQUITY		
Current Liabilities	$ 45,033	$ 67,779
Noncurrent Liabilities	257,109	176,163
Equity	314	391
Total Liabilities and Equity	$ 302,456	$ 244,333

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V 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. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended September 30, 2012 and 2011 were $23 million and $6 million, respectively, and for the nine months ended September 30, 2012 and 2011 were $82 million and $49 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 respective lease terms, which do not exceed 54 months. Based on I&M's 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 table below for the classification of DCC Fuel's assets and liabilities on I&M's condensed balance sheets.

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2012 and December 31, 2011
(in thousands)

	DCC Fuel	
ASSETS	2012	2011
Current Assets	$ 154,774	$ 118,144
Net Property, Plant and Equipment	208,185	188,375
Other Noncurrent Assets	113,519	117,772
Total Assets	$ 476,478	$ 424,291
LIABILITIES AND EQUITY		

Current Liabilities	$	128,466	$	102,946
Noncurrent Liabilities		348,012		321,345
Equity		-		-
Total Liabilities and Equity	$	476,478	$	424,291

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and 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, 2012 and 2011 were $20 million and $18 million, respectively, and for the nine months ended September 30, 2012 and 2011 were $54 million and $47 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's condensed balance sheets.

SWEPCo's investment in DHLC was:

	September 30, 2012		December 31, 2011	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
Capital Contribution from SWEPCo	$ 7,643	$ 7,643	$ 7,643	$ 7,643
Retained Earnings	1,126	1,126	1,120	1,120
SWEPCo's Guarantee of Debt	-	53,278	-	52,310
Total Investment in DHLC	$ 8,769	$ 62,047	$ 8,763	$ 61,073

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

Company	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
	(in thousands)			
APCo	$ 47,820	$ 52,105	$ 130,260	$ 144,398
I&M	31,134	32,127	88,618	94,961
OPCo	72,751	73,664	193,686	210,533
PSO	21,728	21,924	60,625	62,471
SWEPCo	33,154	35,101	93,120	96,494

153

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

Company	September 30, 2012 As Reported on the Balance Sheet	September 30, 2012 Maximum Exposure	December 31, 2011 As Reported on the Balance Sheet	December 31, 2011 Maximum Exposure
	(in thousands)			
APCo	$ 18,989	$ 18,989	$ 20,812	$ 20,812
I&M	12,654	12,654	13,741	13,741
OPCo	27,379	27,379	29,823	29,823
PSO	9,105	9,105	9,280	9,280
SWEPCo	14,054	14,054	14,699	14,699

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo leases the Lawrenceburg Generating Station to OPCo. AEP guarantees all the debt obligations of AEGCo. I&M and OPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and OPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M, OPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see the "Rockport Lease" section of Note 12 in the 2011 Annual Report.

Total billings from AEGCo were as follows:

Company	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in thousands)			
I&M	$ 65,051	$ 64,948	$ 177,790	$ 167,620
OPCo	46,184	47,712	149,424	139,729

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

Company	September 30, 2012 As Reported on the Balance Sheet	September 30, 2012 Maximum Exposure	December 31, 2011 As Reported on the Balance Sheet	December 31, 2011 Maximum Exposure
	(in thousands)			
I&M	$ 22,450	$ 22,450	$ 25,731	$ 25,731
OPCo	12,006	12,006	22,139	22,139

CSPCo-OPCo Merger

On December 31, 2011, CSPCo merged into OPCo with OPCo being the surviving entity. All prior reported amounts have been recast as if the merger occurred on the first day of the earliest reporting period. All contracts and operations of CSPCo and its subsidiary are now part of OPCo.

2. RATE MATTERS

As discussed in the 2011 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2011 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 2012 and updates the 2011 Annual Report.

Regulatory Assets Not Yet Being Recovered

	APCo	
	September 30, 2012	December 31, 2011
Noncurrent Regulatory Assets (excluding fuel)	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Earning a Return		
Expanded Net Energy Charge	$ 8,775	$ -
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	62,400	-
Virginia Environmental Rate Adjustment Clause	23,204	17,950
Mountaineer Carbon Capture and Storage Product Validation Facility	14,155	14,155
Special Rate Mechanism for Century Aluminum	13,002	12,811
Dresden Operating Costs	8,758	-
Virginia Deferred Wind Power Costs	4,355	38,192
Transmission Agreement Phase-In	2,803	1,925
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,291	1,335
Other Regulatory Assets Not Yet Being Recovered	1,308	1,010
Total Regulatory Assets Not Yet Being Recovered	$ 140,051	$ 87,378

	I&M	
	September 30, 2012	December 31, 2011
Noncurrent Regulatory Assets (excluding fuel)	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Not Earning a Return		
Litigation Settlement	$ 11,027	$ 10,803
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,384	1,680
Other Regulatory Asset Not Yet Being Recovered	899	-
Total Regulatory Assets Not Yet Being Recovered	$ 13,310	$ 12,483

	OPCo	
Noncurrent Regulatory Assets (excluding fuel)	September 30, 2012	December 31, 2011
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Earning a Return		
Economic Development Rider	$ 13,053	$ 12,572
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	53,600	8,375
Total Regulatory Assets Not Yet Being Recovered	$ 66,653	$ 20,947

	PSO	
Noncurrent Regulatory Assets (excluding fuel)	September 30, 2012	December 31, 2011
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Not Earning a Return		
Environmental Compliance Costs	$ 351	$ -
Total Regulatory Assets Not Yet Being Recovered	$ 351	$ -

	SWEPCo	
Noncurrent Regulatory Assets (excluding fuel)	September 30, 2012	December 31, 2011
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Not Earning a Return		
Rate Case Expenses	$ 3,673	$ -
Mountaineer Carbon Capture and Storage		
Commercial Scale Facility	2,301	2,380
Other Regulatory Assets Not Yet Being Recovered	2,099	1,699
Total Regulatory Assets Not Yet Being Recovered	$ 8,073	$ 4,079

If these costs are ultimately determined not to be recoverable, it would reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. See the "January 2012 – May 2016 ESP as Rejected by the PUCO" section below. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the Industrial Energy Users-Ohio (IEU) filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could result in a refund of up to $698 million, excluding carrying costs.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. In May 2011, the IEU and the Ohio Energy Group (OEG) filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. The OEG's appeal seeks the inclusion of off-system sales (OSS) in the calculation of SEET which, if ordered, could require an additional refund of $22 million based on the PUCO approved SEET calculation. The IEU's appeal also sought the inclusion of OSS as well as other items in the determination of SEET, but did not quantify the amount. Oral arguments were held in March 2012 and management is unable to predict the outcome of the appeals.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included OSS in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO in 2012 on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo.

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.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved a modified stipulation which established a new ESP that included a standard service offer (SSO) pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the PIRR deferral in accordance with the 2009 - 2011 ESP order. Also in March 2012, OPCo filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. As of September 30, 2012, OPCo's net PIRR deferral was $536 million, excluding unrecognized equity carrying costs.

As a result of the PUCO's rejection of the modified stipulation, in the first quarter of 2012, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in the fourth quarter of 2011.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that will freeze base generation rates through May 2015, adopt a 12% earnings threshold for the SEET and allow the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the ESP approved a storm damage recovery mechanism which allowed OPCo to defer the majority of the incremental distribution operation and maintenance costs from 2012 storms. As of September 30, 2012, OPCo recorded $54 million in Regulatory Assets on the condensed balance sheets related to the 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of ESP and corporate separation orders and extending through December 2014. The PUCO also ordered OPCo to conduct an energy-only auction for a total of 60% of the SSO load with delivery beginning June 2014 through May 2015. In addition, the PUCO ordered OPCo to conduct an energy-only auction for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. Starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers to the extent that the total incurred capacity costs do not exceed $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. The order stated that the PUCO would establish an appropriate recovery mechanism in the June 2012 – May 2015 ESP proceeding. In July 2012, several parties, including OPCo, requested rehearing of the July 2012 PUCO order on capacity, which was upheld by the PUCO in October 2012.

In the August 2012 PUCO order which adopted and modified the new ESP, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide $508 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. In August 2012, the IEU filed a claim before the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss IEU's claim. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition.

In September 2012, OPCo and intervenors filed applications with the PUCO for rehearing of the August 2012 ESP order. Rehearing of this order is pending at the PUCO. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

158

Proposed Corporate Separation

In March 2012, OPCo filed an application with the PUCO for approval of the corporate separation of its generation assets including the transfer of generation assets to a nonregulated AEP subsidiary at net book value. In October 2012, the PUCO issued an order which approved the transfer of OPCo's generation assets at net book value to AEP Generation Resources, Inc. (AEPGenCo), a nonregulated affiliate in the Generation and Marketing segment. AEPGenCo will also assume the associated generation liabilities.

An additional filing at the FERC related to corporate separation is expected in the fourth quarter of 2012. Prior to corporate separation, OPCo's results of operations related to generation could be affected by the ability to sell power and capacity at a profit at rates determined by the prevailing market. If power and capacity are not sold at a profit, it could reduce OPCo's future net income and cash flows and impact financial condition.

2011 Ohio Distribution Base Rate Case

In February 2011, OPCo filed with the PUCO for an annual increase in distribution rates of $94 million based upon an 11.15% return on common equity to be effective January 2012. In December 2011, a stipulation was approved by the PUCO which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved by the modified stipulation in the ESP proceeding.

Since the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as filed in the ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. See the "June 2012 – May 2015 ESP Including Capacity Charge" section above.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultants' review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, an intervenor filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audits reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the

carrying costs on the balance should be net of accumulated income taxes. As of September 30, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $38 million, including $20 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

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 filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent 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 OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through September 30, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. 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 these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could 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 scheduled to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.8 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $122 million for transmission, excluding AFUDC. As of September 30, 2012, excluding costs attributable to its joint owners and a $62 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.7 billion of expenditures, including AFUDC and capitalized interest of $296 million for generation and related transmission costs of $127 million. As of September 30, 2012, the joint owners and SWEPCo have contractual construction obligations of approximately $42 million, including related transmission costs of $3 million. SWEPCo's share of the contractual construction obligations is $31 million.

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. SWEPCo announced that it would continue construction of the Turk Plant and would

not currently seek authority to serve Arkansas retail customers from the Turk Plant. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. SWEPCo currently has no contracts for the 88 MW of Turk Plant output but is evaluating options.

The PUCT approved 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 (TIEC) 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. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and TIEC filed petitions for review at the Supreme Court of Texas. The Supreme Court of Texas has requested full briefing from the parties.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could materially reduce future net income and cash flows and materially impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operations and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant, Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures recovered from ratepayers and (c) included a return on and of the Stall Unit as of December 2011 and associated operations and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it could reduce future net income and cash flows and impact financial condition.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. Through September 30, 2012, SWEPCo has incurred $10 million related to this project, including AFUDC. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing at the APSC was held in October 2012 and a decision is pending from the APSC. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Louisiana 2010 Formula Rate Filing

In April 2010, SWEPCo filed its formula rate plan (FRP) which decreased annual Louisiana retail rates by $3 million effective August 2010, subject to refund. In October 2010 and September 2011, consultants for the LPSC filed testimony objecting to certain components of SWEPCo's FRP calculations. A settlement agreement was reached by the parties and orally approved by the LPSC in September 2012. The reserve recorded in the second quarter of 2012 was increased by an immaterial amount to cover the $3 million refund approved by the LPSC in the settlement agreement. The refund began in October 2012 and will occur over a twelve-month period.

161

APCo Rate Matters

Virginia Fuel Filing

In April 2012, APCo filed an application with the Virginia SCC for an annual increase in fuel revenues of $117 million to be effective June 2012. The filing included forecasted costs for the 15-month period ended August 2013 and requested recovery of APCo's anticipated unrecovered fuel balance as of May 2012 over a two-year period commencing in June 2012. The non-incremental portion of APCo's forecasted and deferred wind purchased power costs were reflected in APCo's filing. In June 2012, the Virginia SCC approved the application as filed.

Environmental Rate Adjustment Clause (Environmental RAC)

In November 2011, the Virginia SCC issued an order which approved APCo’s environmental RAC recovery of $30 million to be collected over one year beginning in February 2012 but denied recovery of certain environmental costs. As a result, in the fourth quarter of 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. In December 2011, APCo filed a notice of appeal with the Supreme Court of Virginia regarding this decision. A decision is expected in the fourth quarter of 2012. If the Supreme Court of Virginia were to issue a favorable decision, it could increase future net income and cash flows.

Generation Rate Adjustment Clause (Generation RAC)

In January 2012, the Virginia SCC issued a generation RAC order which allowed APCo to recover $26 million annually, effective March 2012, related to recovery of the Dresden Plant. In March 2012, APCo filed with the Virginia SCC to continue the current generation RAC rate to recover costs of the Dresden Plant through February 2014. In August 2012, the Virginia SCC staff filed testimony that recommended a $5 million increase in the revenue requirement, including the under-recovered balance of $3 million as of April 2012. The Virginia SCC staff also recommended an alternative proposal to not change rates and not allow APCo to accrue carrying charges on any under-recovered generation RAC balances. A decision is expected in the fourth quarter of 2012. If the Virginia SCC were to disallow any portion of the generation RAC, it could reduce future net income and cash flows and impact financial condition.

APCo’s Filings for an IGCC Plant

Through September 30, 2012, 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. 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 March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. Also in March 2012, APCo and WPCo filed their ENEC application with the WVPSC for the fourth year of a four-year phase-in plan which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral and other ENEC related assets. If the financing order is not issued, APCo and WPCo requested that recovery of these costs be allowed in current rates.

In July 2012, the WVPSC issued an interim order that approved a settlement agreement which recommended no change in total ENEC rates but reflected a $24 million increase in the construction surcharge and a $24 million

decrease in ENEC rates. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to the December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. As of September 30, 2012, APCo's ENEC under-recovery balance of $307 million was recorded in Regulatory Assets on the condensed balance sheet, excluding $5 million of unrecognized equity carrying costs. A hearing is scheduled for December 2012.

WPCo Merger with APCo

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. In December 2011 and February 2012, APCo and WPCo filed merger applications with the WVPSC and the FERC, respectively. In February 2012, APCo and WPCo withdrew their merger application with the FERC. Management intends to refile a merger application with the FERC and also file a merger application with the Virginia SCC in the fourth quarter of 2012.

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 prudence 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%. In October 2012, the OCC issued a final order that found PSO’s fuel and purchased power costs were prudently incurred without any disallowance and that PSO’s shareholder’s portion of off-system sales margins would remain at 25%.

I&M Rate Matters

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 $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015.

In May 2012, the Indiana Office of Utility Consumer Counselor filed testimony that recommended an increase in base rates of $28 million, excluding reductions to certain riders, based upon a return on common equity of 9.2%. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders. Final hearings were held in June 2012. A decision from the IURC is expected in the fourth quarter of 2012. If the IURC disallows cost recovery, it could reduce future net income and cash flows and impact financial condition.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant Units 1 and 2. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an

interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of September 30, 2012, I&M has incurred $109 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. A hearing at the IURC is scheduled for January 2013.

Also in August 2012, the MPSC staff and other intervenors filed testimony in Michigan. The recommendations ranged from the Association of Businesses Advocating Tariff Equity's denial of deferral of costs but recovery of costs considered in future base rate cases to the Attorney General allowing recovery of LCM project costs of $848 million. If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows.

Rockport Plant

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of September 30, 2012, I&M has incurred $24 million, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

In July 2012, certain intervenors filed testimony which recommended cost caps ranging from $1.1 billion to $1.4 billion if the IURC approved the CPCN. In addition, the Indiana Office of Utility Consumer Counselor recommended the CPCN be denied until a more detailed project plan and cost estimates are filed with the IURC. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. A hearing is scheduled for December 2012.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund – Affecting APCo, I&M and OPCo

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and 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. APCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)
APCo	$ 70.2
I&M	41.3
OPCo	92.1

In 2006, a FERC Administrative Law Judge 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.

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 supported AEP's position and required a compliance filing.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. APCo's, I&M's and OPCo's portions of the provision are as follows:

Company	(in millions)
APCo	$ 14.1
I&M	8.3
OPCo	18.5

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. A decision is pending from the FERC. APCo's, I&M's and OPCo's portions of potential refund payments are as follows:

Company	Potential Refund Payments (in millions)
APCo	$ 6.4
I&M	3.7
OPCo	8.3

Not all parties have agreed to the compliance filing. In August 2012, the FERC issued an order approving a settlement agreement resulting in the AEP East companies' October 2012 collection of $8 million of previously deemed uncollectible SECA revenue. There was no change in the reserve for net refunds due to the remaining uncertainty around negotiations with certain parties who have not agreed to the compliance filing. The balance in the reserve for future settlements as of September 30, 2012 was $31 million. APCo's, I&M's and OPCo's reserve balances as of September 30, 2012 were:

Company	September 30, 2012 (in millions)
APCo	$ 10.0
I&M	5.9
OPCo	13.1

Based on the analysis of the May 2010 order, the compliance filing and recent settlements, 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 – Affecting APCo, I&M and OPCo

In December 2010, each of the members of the Interconnection Agreement gave notice to AEPSC and each other of its decision to terminate the Interconnection Agreement effective as of December 31, 2013 or such other date as ordered by the FERC. Management intends to file an application with the FERC in the fourth quarter of 2012 to terminate the Interconnection Agreement. It is unknown whether the Interconnection Agreement 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. If any of the members of the Interconnection Agreement experience decreases in revenues or increases in costs as a result of the termination of the Interconnection Agreement 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.

3. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2011 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two credit facilities totaling $3.25 billion, under which up to $1.35 billion may be issued as letters of credit. As of September 30, 2012, the maximum future payments for letters of credit issued under the credit facilities were as follows:

Company	Amount (in thousands)	Maturity
I&M	$ 150	March 2013
OPCo	2,102	June 2013
SWEPCo	4,448	March 2013

The Registrant Subsidiaries have $357 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $361 million as follows:

Company	Pollution Control Bonds	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
	(in thousands)		
APCo	$ 229,650	$ 232,293	March 2013 to March 2014
I&M	77,000	77,886	March 2013
OPCo	50,000	50,575	March 2013

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of September 30, 2012, SWEPCo has collected approximately $58 million through a rider for final mine closure and reclamation costs, of which $10 million is recorded in Other Current Liabilities, $7 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $41 million is recorded in Asset Retirement Obligations on SWEPCo's 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 – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2012, there were no material liabilities recorded for any indemnifications.

APCo, I&M and OPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to power purchase and sale activity pursuant to the SIA. PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Master Lease Agreements

The Registrant Subsidiaries lease certain equipment under master lease agreements. Under the 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, the Registrant Subsidiaries are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of September 30, 2012, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss (in thousands)
APCo	$ 3,132
I&M	2,426
OPCo	3,556
PSO	1,167
SWEPCo	2,559

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 $15 million and $17 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2012.

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. The maximum potential losses related to the guarantee are approximately $12 million and $13 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs have filed a petition for rehearing by the full court. Management believes the action is without merit and will continue to defend against the claims. Management is 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 – Affecting I&M

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrant Subsidiaries 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 $10 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. Management cannot predict the amount of additional cost, if any.

168

NUCLEAR CONTINGENCIES – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. I&M has 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 cost approximately $400 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. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. 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, 2012, I&M recorded $64 million on its condensed balance sheet representing amounts recoverable from NEIL under the insurance policies. Through September 30, 2012, I&M received payments from NEIL of $203 million for the cost incurred to date to repair the property damage and $185 million under an accidental outage policy.

The claims process with NEIL continues and includes a review of claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies, 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. 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 reduce future net income and cash flows and impact financial condition.

4. ACQUISITION AND IMPAIRMENTS

ACQUISITION

2011

Dresden Plant – Affecting APCo

In August 2011, APCo purchased the partially completed Dresden Plant from AEGCo, at cost, for $302 million. The Dresden Plant was completed and placed in service in January 2012. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant with a generating capacity of 580 MW.

IMPAIRMENTS

2012

Turk Plant (Utility Operations segment) – Affecting SWEPCo

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the condensed statements of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

2011

Muskingum River Plant Unit 5 FGD Project (MR5) – Affecting OPCo

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 – Affecting OPCo

In the third quarter of 2011, management decided to no longer offer the output of 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 Interconnection Agreement. 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.

5. BENEFIT PLANS

The Registrant Subsidiaries participate in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified plan and a nonqualified pension plan. The Registrant Subsidiaries also participate in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost by Registrant Subsidiary for the plans for the three and nine months ended September 30, 2012 and 2011:

APCo	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 1,892	$ 1,799	$ 1,346	$ 1,245
Interest Cost	7,553	8,073	4,616	4,867
Expected Return on Plan Assets	(10,486)	(10,458)	(4,188)	(4,496)
Amortization of Transition Obligation	-	-	201	286
Amortization of Prior Service Cost (Credit)	118	230	(716)	(42)
Amortization of Net Actuarial Loss	5,085	4,142	2,631	1,465
Net Periodic Benefit Cost	$ 4,162	$ 3,786	$ 3,890	$ 3,325

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			

Service Cost	$ 5,674	$ 5,399	$ 4,040	$ 3,737
Interest Cost	22,659	24,219	13,847	14,601
Expected Return on Plan Assets	(31,458)	(31,374)	(12,564)	(13,488)
Amortization of Transition Obligation	-	-	601	859
Amortization of Prior Service Cost (Credit)	356	688	(2,147)	(128)
Amortization of Net Actuarial Loss	15,254	12,427	7,894	4,379
Net Periodic Benefit Cost	$ 12,485	$ 11,359	$ 11,671	$ 9,960

I&M

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 2,477	$ 2,362	$ 1,655	$ 1,531
Interest Cost	6,562	6,931	3,196	3,402
Expected Return on Plan Assets	(9,392)	(9,213)	(3,212)	(3,471)
Amortization of Transition Obligation	-	-	33	47
Amortization of Prior Service Cost (Credit)	101	186	(595)	(59)
Amortization of Net Actuarial Loss	4,392	3,536	1,762	891
Net Periodic Benefit Cost	$ 4,140	$ 3,802	$ 2,839	$ 2,341

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 7,431	$ 7,085	$ 4,965	$ 4,590
Interest Cost	19,684	20,794	9,589	10,207
Expected Return on Plan Assets	(28,175)	(27,641)	(9,635)	(10,414)
Amortization of Transition Obligation	-	-	99	141
Amortization of Prior Service Cost (Credit)	305	558	(1,787)	(177)
Amortization of Net Actuarial Loss	13,177	10,608	5,287	2,674
Net Periodic Benefit Cost	$ 12,422	$ 11,404	$ 8,518	$ 7,021

OPCo

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 2,751	$ 2,557	$ 2,187	$ 1,957
Interest Cost	11,298	12,087	6,047	6,375
Expected Return on Plan Assets	(17,100)	(16,364)	(5,639)	(6,129)
Amortization of Transition Obligation	-	-	26	37
Amortization of Prior Service Cost (Credit)	186	368	(969)	(53)
Amortization of Net Actuarial Loss	7,610	6,207	3,418	2,265
Net Periodic Benefit Cost	$ 4,745	$ 4,855	$ 5,070	$ 4,452

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 8,253	$ 7,672	$ 6,561	$ 5,870
Interest Cost	33,895	36,263	18,142	19,123
Expected Return on Plan Assets	(51,301)	(49,097)	(16,917)	(18,385)
Amortization of Transition Obligation	-	-	78	112
Amortization of Prior Service Cost (Credit)	557	1,104	(2,905)	(160)
Amortization of Net Actuarial Loss	22,830	18,621	10,252	5,914
Net Periodic Benefit Cost	$ 14,234	$ 14,563	$ 15,211	$ 12,474

PSO

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 1,487	$ 1,440	$ 709	$ 655
Interest Cost	3,076	3,321	1,449	1,512
Expected Return on Plan Assets	(4,503)	(4,366)	(1,480)	(1,566)
Amortization of Prior Service Credit	(237)	(238)	(270)	(19)
Amortization of Net Actuarial Loss	2,051	1,690	797	389
Net Periodic Benefit Cost	$ 1,874	$ 1,847	$ 1,205	$ 971

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 4,463	$ 4,320	$ 2,127	$ 1,966
Interest Cost	9,226	9,964	4,348	4,535
Expected Return on Plan Assets	(13,511)	(13,098)	(4,441)	(4,698)
Amortization of Prior Service Credit	(711)	(713)	(809)	(57)
Amortization of Net Actuarial Loss	6,154	5,068	2,391	1,165
Net Periodic Benefit Cost	$ 5,621	$ 5,541	$ 3,616	$ 2,911

SWEPCo

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 1,775	$ 1,644	$ 831	$ 757
Interest Cost	3,134	3,333	1,669	1,742
Expected Return on Plan Assets	(4,717)	(4,596)	(1,699)	(1,800)
Amortization of Prior Service Cost (Credit)	(198)	(199)	(234)	64
Amortization of Net Actuarial Loss	2,083	1,690	915	447
Net Periodic Benefit Cost	$ 2,077	$ 1,872	$ 1,482	$ 1,210

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			

Service Cost	$ 5,324	$ 4,930	$ 2,493	$ 2,271
Interest Cost	9,403	9,999	5,005	5,227
Expected Return on Plan Assets	(14,150)	(13,786)	(5,096)	(5,400)
Amortization of Prior Service Cost (Credit)	(595)	(597)	(700)	193
Amortization of Net Actuarial Loss	6,248	5,070	2,744	1,339
Net Periodic Benefit Cost	$ 6,230	$ 5,616	$ 4,446	$ 3,630

6. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and marketers 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 the Registrant Subsidiaries due to changes in the underlying market prices or rates. AEPSC, on behalf of the Registrant Subsidiaries, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of the Registrant Subsidiaries. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs 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.

AEPSC, on behalf of the Registrant Subsidiaries, enters 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 the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the Registrant Subsidiaries’ commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. AEPSC, on behalf of the Registrant Subsidiaries, also engages 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 established risk management policies as approved by the Finance Committee of AEP’s Board of Directors.

The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of September 30, 2012 and December 31, 2011:

Notional Volume of Derivative Instruments
September 30, 2012

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWHs	142,425	98,176	200,993	14	16
Coal	Tons	2,498	2,944	5,052	2,416	2,241
Natural Gas	MMBtus	11,127	7,647	15,703	13	15
Heating Oil and Gasoline	Gallons	858	440	1,041	494	471
Interest Rate	USD	$ 29,011	$ 19,936	$ 40,940	$ -	$ -
Interest Rate and Foreign Currency	USD	$ -	$ 200,000	$ -	$ -	$ -

Notional Volume of Derivative Instruments
December 31, 2011

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWHs	169,459	109,326	229,468	39	49
Coal	Tons	3,714	1,920	8,337	3,574	2,974
Natural Gas	MMBtus	7,923	5,081	10,728	115	145
Heating Oil and Gasoline	Gallons	1,057	525	1,254	618	569
Interest Rate	USD	$ 31,029	$ 19,890	$ 42,093	$ 175	$ 203
Interest Rate and Foreign Currency	USD	$ -	$ 200,000	$ -	$ -	$ 200,069

Fair Value Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters 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 an exposure to interest rate risk by converting a portion of 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

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates 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. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions

to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted 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. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrant Subsidiaries do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE 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 sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrant Subsidiaries 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 management's 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2012 and December 31, 2011 balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	September 30, 2012		December 31, 2011	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)			

APCo	$ 2,375	$ 10,408	$ 4,291	$ 28,964
I&M	1,632	7,151	2,752	18,547
OPCo	3,352	14,687	5,810	39,183
PSO	5	9	53	130
SWEPCo	6	9	66	124

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the condensed balance sheets as of September 30, 2012 and December 31, 2011:

Fair Value of Derivative Instruments
September 30, 2012

APCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 165,813	$ 1,307	$ -	$ (135,893)	$ 31,227
Long-term Risk Management Assets	82,738	291	-	(44,658)	38,371
Total Assets	248,551	1,598	-	(180,551)	69,598
Current Risk Management Liabilities	157,836	1,757	-	(141,267)	18,326
Long-term Risk Management Liabilities	68,293	419	-	(47,907)	20,805
Total Liabilities	226,129	2,176	-	(189,174)	39,131
Total MTM Derivative Contract Net Assets (Liabilities)	$ 22,422	$ (578)	$ -	$ 8,623	$ 30,467

Fair Value of Derivative Instruments
December 31, 2011

APCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 232,784	$ 1,040	$ -	$ (194,179)	$ 39,645
	99,751	90	-	(60,615)	39,226

Long-term Risk Management Assets					
Total Assets	332,535	1,130	-	(254,794)	78,871
Current Risk Management Liabilities	235,354	2,767	-	(211,515)	26,606
Long-term Risk Management Liabilities	82,058	350	-	(69,485)	12,923
Total Liabilities	317,412	3,117	-	(281,000)	39,529
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,123	$ (1,987)	$ -	$ 26,206	$ 39,342

Fair Value of Derivative Instruments
September 30, 2012

I&M

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 118,202	$ 882	$ -	$ (90,582)	$ 28,502
Long-term Risk Management Assets	56,711	199	-	(30,606)	26,304
Total Assets	174,913	1,081	-	(121,188)	54,806
Current Risk Management Liabilities	105,794	1,204	20,465	(94,275)	33,188
Long-term Risk Management Liabilities	47,380	287	-	(32,838)	14,829
Total Liabilities	153,174	1,491	20,465	(127,113)	48,017
Total MTM Derivative Contract Net Assets (Liabilities)	$ 21,739	$ (410)	$ (20,465)	$ 5,925	$ 6,789

Fair Value of Derivative Instruments
December 31, 2011

I&M

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 154,628	$ 667	$ -	$ (123,143)	$ 32,152
Long-term Risk Management Assets	68,047	58	-	(38,743)	29,362
Total Assets	222,675	725	-	(161,886)	61,514
Current Risk Management Liabilities	149,466	1,747	-	(134,233)	16,980
	52,441	224	10,637	(44,431)	18,871

Long-term Risk Management Liabilities					
Total Liabilities	201,907	1,971	10,637	(178,664)	35,851
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,768	$ (1,246)	$ (10,637)	$ 16,778	$ 25,663

177

Fair Value of Derivative Instruments
September 30, 2012

OPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 242,904	$ 1,827	$ -	$ (200,027)	$ 44,704
Long-term Risk Management Assets	117,272	410	-	(63,355)	54,327
Total Assets	360,176	2,237	-	(263,382)	99,031
Current Risk Management Liabilities	231,792	2,477	-	(207,611)	26,658
Long-term Risk Management Liabilities	96,861	591	-	(67,939)	29,513
Total Liabilities	328,653	3,068	-	(275,550)	56,171
Total MTM Derivative Contract Net Assets (Liabilities)	$ 31,523	$ (831)	$ -	$ 12,168	$ 42,860

Fair Value of Derivative Instruments
December 31, 2011

OPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 325,904	$ 1,409	$ -	$ (273,020)	$ 54,293
Long-term Risk Management Assets	136,519	122	-	(83,027)	53,614

Total Assets	462,423	1,531	-	(356,047)	107,907
Current Risk Management Liabilities	329,307	3,712	-	(296,458)	36,561
Long-term Risk Management Liabilities	112,454	474	-	(95,038)	17,890
Total Liabilities	441,761	4,186	-	(391,496)	54,451
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,662	$ (2,655)	$ -	$ 35,449	$ 53,456

Fair Value of Derivative Instruments
September 30, 2012

PSO

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 4,868	$ 54	$ -	$ (4,377)	$ 545
Long-term Risk Management Assets	300	4	-	(180)	124
Total Assets	5,168	58	-	(4,557)	669
Current Risk Management Liabilities	9,435	13	-	(4,377)	5,071
Long-term Risk Management Liabilities	1,230	5	-	(184)	1,051
Total Liabilities	10,665	18	-	(4,561)	6,122
Total MTM Derivative Contract Net Assets (Liabilities)	$ (5,497)	$ 40	$ -	$ 4	$ (5,453)

Fair Value of Derivative Instruments
December 31, 2011

PSO

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 6,980	$ -	$ -	$ (6,415)	$ 565
Long-term Risk Management Assets	914	-	-	(600)	314

Total Assets	7,894	-	-	(7,015)	879
Current Risk Management Liabilities	7,665	107	-	(6,492)	1,280
Long-term Risk Management Liabilities	1,930	-	-	(600)	1,330
Total Liabilities	9,595	107	-	(7,092)	2,610
Total MTM Derivative Contract Net Assets (Liabilities)	$ (1,701)	$ (107)	$ -	$ 77	$ (1,731)

Fair Value of Derivative Instruments
September 30, 2012

SWEPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 7,888	$ 51	$ -	$ (7,234)	$ 705
Long-term Risk Management Assets	467	4	-	(293)	178
Total Assets	8,355	55	-	(7,527)	883
Current Risk Management Liabilities	11,369	12	-	(7,233)	4,148
Long-term Risk Management Liabilities	425	6	-	(297)	134
Total Liabilities	11,794	18	-	(7,530)	4,282
Total MTM Derivative Contract Net Assets (Liabilities)	$ (3,439)	$ 37	$ -	$ 3	$ (3,399)

Fair Value of Derivative Instruments
December 31, 2011

SWEPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 6,327	$ -	$ 3	$ (5,885)	$ 445
Long-term Risk Management Assets	818	-	-	(536)	282
Total Assets	7,145	-	3	(6,421)	727
Current Risk Management Liabilities	11,062	97	19,143	(5,943)	24,359
Long-term Risk Management Liabilities	757	-	-	(536)	221

Total Liabilities	11,819	97	19,143	(6,479)	24,580
Total MTM Derivative Contract Net Assets (Liabilities)	$ (4,674)	$ (97)	$ (19,140)	$ 58	$ (23,853)

(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 the Registrant Subsidiaries' activity of derivative risk management contracts for the three and nine months ended September 30, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2012

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 378	$ 3,814	$ 87	$ 71	$ 174
Sales to AEP Affiliates	-	-	-	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Regulatory Assets (a)	(138)	(1,213)	3,000	598	115
Regulatory Liabilities (a)	(1,672)	(5,267)	(6,788)	2	11
Total Gain (Loss) on Risk Management Contracts	$ (1,432)	$ (2,666)	$ (3,701)	$ 671	$ 300

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

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 960	$ 3,094	$ 4,652	$ (530)	$ (186)
Sales to AEP Affiliates	103	58	126	2	2
Fuel and Other Consumables Used for Electric Generation	-	-	(2)	-	-
Regulatory Assets (a)	139	71	(2,846)	(264)	(219)
Regulatory Liabilities (a)	(1,058)	(2,566)	26	1,930	174
Total Gain (Loss) on Risk Management Contracts	$ 144	$ 657	$ 1,956	$ 1,138	$ (229)

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2012

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and					

Distribution Revenues	$ (548)	$ 9,206	$ 11,118	$ 231	$ 426
Sales to AEP Affiliates	-	-	-	-	-
Fuel and Other Consumables Used for					
Electric Generation	-	-	-	-	-
Regulatory Assets (a)	(6,133)	(7,228)	(9,026)	(5,360)	(6,977)
Regulatory Liabilities (a)	8,166	1,851	390	3	6
Total Gain (Loss) on Risk Management					
Contracts	$ 1,485	$ 3,829	$ 2,482	$ (5,126)	$ (6,545)

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

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 3,659	$ 12,211	$ 26,806	$ 128	$ 340
Sales to AEP Affiliates	136	81	171	2	2
Fuel and Other Consumables Used for Electric Generation	-	-	(2)	-	-
Regulatory Assets (a)	373	186	(7,028)	285	2,975
Regulatory Liabilities (a)	9,827	(4,230)	(105)	2,509	58
Total Gain (Loss) on Risk Management Contracts	$ 13,995	$ 8,248	$ 19,842	$ 2,924	$ 3,375

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

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for “Derivatives and Hedging.” Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the condensed statements of income on an accrual basis.

The 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, management designates 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 (APCo, I&M, PSO and SWEPCo) 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.

The Registrant Subsidiaries 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 the condensed statements of income. During the three and nine months ended September 30, 2012 and 2011, the Registrant Subsidiaries did not designate any fair value hedging strategies.

182

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries 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 and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on the condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2012 and 2011, APCo, I&M and OPCo designated power, coal and natural gas derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three and nine months ended September 30, 2012 and 2011, the Registrant Subsidiaries designated heating oil and gasoline derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Interest Expense on the condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2012, I&M and SWEPCo designated interest rate derivatives as cash flow hedges. During the three and nine months ended September 30, 2011, I&M and SWEPCo designated interest rate derivatives as cash flow hedges. During the nine months ended September 30, 2011, APCo and PSO designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2012 and 2011, SWEPCo designated foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2012 and 2011, 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 the condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2012 and 2011. 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, 2012

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of June 30, 2012	$ (1,820)	$ (1,246)	$ (2,639)	$ (102)	$ (97)
Changes in Fair Value Recognized in AOCI	1,302	887	1,915	126	123
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	(4)	(10)	(23)	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	35	88	221	-	-
Other Operation Expense	(4)	(1)	(6)	-	1
Maintenance Expense	12	4	7	5	4
Property, Plant and Equipment	3	1	1	5	3
Regulatory Assets (a)	114	20	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2012	$ (362)	$ (257)	$ (524)	$ 34	$ 34

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of June 30, 2012	$ 1,562	$ (19,015)	$ 8,774	$ 6,839	$ (16,806)
Changes in Fair Value Recognized in AOCI	-	(1,542)	1	1	(1)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	-	1	-	-
Interest Expense	261	149	(341)	(190)	567

Balance in AOCI as of September 30, 2012	$ 1,823	$ (20,408)	$ 8,435	$ 6,650	$ (16,240)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of June 30, 2012	$ (258)	$ (20,261)	$ 6,135	$ 6,737	$ (16,903)
Changes in Fair Value Recognized in AOCI	1,302	(655)	1,916	127	122
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	(4)	(10)	(23)	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	35	88	221	-	-
Other Operation Expense	(4)	(1)	(6)	-	1
Maintenance Expense	12	4	7	5	4
Depreciation and Amortization Expense	-	-	1	-	-
Interest Expense	261	149	(341)	(190)	567
Property, Plant and Equipment	3	1	1	5	3
Regulatory Assets (a)	114	20	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2012	$ 1,461	$ (20,665)	$ 7,911	$ 6,684	$ (16,206)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2011

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of June 30, 2011	$ 669	$ 378	$ 837	$ 140	$ 132
Changes in Fair Value Recognized in AOCI	(646)	(332)	(765)	(162)	(148)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	84	167	461	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	(70)	(148)	(402)	-	-
Other Operation Expense	(32)	(22)	(50)	(28)	(28)
Maintenance Expense	(51)	(21)	(46)	(20)	(21)
Property, Plant and Equipment	(51)	(28)	(63)	(32)	(27)
Regulatory Assets (a)	53	5	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2011	$ (44)	$ (1)	$ (28)	$ (102)	$ (92)

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of June 30, 2011	$ 486	$ (8,004)	$ 10,133	$ 7,598	$ (3,057)
Changes in Fair Value Recognized in AOCI	-	(4,764)	-	-	(10,896)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	-	1	-	-
Interest Expense	269	252	(340)	(190)	207
Balance in AOCI as of September 30, 2011	$ 755	$ (12,516)	$ 9,794	$ 7,408	$ (13,746)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of June 30, 2011	$ 1,155	$ (7,626)	$ 10,970	$ 7,738	$ (2,925)
Changes in Fair Value Recognized in AOCI	(646)	(5,096)	(765)	(162)	(11,044)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	84	167	461	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	(70)	(148)	(402)	-	-
Other Operation Expense	(32)	(22)	(50)	(28)	(28)
Maintenance Expense	(51)	(21)	(46)	(20)	(21)
Depreciation and Amortization Expense	-	-	1	-	-
Interest Expense	269	252	(340)	(190)	207
Property, Plant and Equipment	(51)	(28)	(63)	(32)	(27)
Regulatory Assets (a)	53	5	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2011	$ 711	$ (12,517)	$ 9,766	$ 7,306	$ (13,838)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2012

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2011	$ (1,309)	$ (819)	$ (1,748)	$ (69)	$ (62)
Changes in Fair Value Recognized in AOCI	(946)	(741)	(1,487)	110	106
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	(7)	(19)	(47)	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	411	1,074	2,806	-	-
Other Operation Expense	(20)	(11)	(30)	(11)	(8)
Maintenance Expense	3	-	(3)	3	1
Property, Plant and Equipment	(9)	(6)	(15)	1	(3)
Regulatory Assets (a)	1,515	265	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2012	$ (362)	$ (257)	$ (524)	$ 34	$ 34

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2011	$ 1,024	$ (14,465)	$ 9,454	$ 7,218	$ (15,462)
Changes in Fair Value Recognized in AOCI	-	(6,390)	1	1	(2,778)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	-	3	-	-
Interest Expense	799	447	(1,023)	(569)	2,000
	$ 1,823	$ (20,408)	$ 8,435	$ 6,650	$ (16,240)

Balance in AOCI as of September 30, 2012

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2011	$ (285)	$ (15,284)	$ 7,706	$ 7,149	$ (15,524)
Changes in Fair Value Recognized in AOCI	(946)	(7,131)	(1,486)	111	(2,672)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	(7)	(19)	(47)	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	411	1,074	2,806	-	-
Other Operation Expense	(20)	(11)	(30)	(11)	(8)
Maintenance Expense	3	-	(3)	3	1
Depreciation and Amortization Expense	-	-	3	-	-
Interest Expense	799	447	(1,023)	(569)	2,000
Property, Plant and Equipment	(9)	(6)	(15)	1	(3)
Regulatory Assets (a)	1,515	265	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2012	$ 1,461	$ (20,665)	$ 7,911	$ 6,684	$ (16,206)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2011

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2010	$ (273)	$ (178)	$ (364)	$ 88	$ 82
Changes in Fair Value Recognized in AOCI	(523)	(279)	(622)	18	20
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	255	553	1,495	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	(24)	(46)	(127)	-	-
Other Operation Expense	(76)	(59)	(133)	(75)	(74)
Maintenance Expense	(141)	(53)	(116)	(49)	(53)
Property, Plant and Equipment	(131)	(67)	(161)	(84)	(67)
Regulatory Assets (a)	869	128	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2011	$ (44)	$ (1)	$ (28)	$ (102)	$ (92)

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2010	$ 217	$ (8,507)	$ 10,813	$ 8,406	$ (4,272)
Changes in Fair Value Recognized in AOCI	(373)	(4,764)	-	(476)	(10,095)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Other Operation Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	-	3	-	-
Interest Expense	911	755	(1,022)	(522)	621
	$ 755	$ (12,516)	$ 9,794	$ 7,408	$ (13,746)

Balance in AOCI as of September 30, 2011

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2010	$ (56)	$ (8,685)	$ 10,449	$ 8,494	$ (4,190)
Changes in Fair Value Recognized in AOCI	(896)	(5,043)	(622)	(458)	(10,075)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	255	553	1,495	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	(24)	(46)	(127)	-	-
Other Operation Expense	(76)	(59)	(133)	(75)	(74)
Maintenance Expense	(141)	(53)	(116)	(49)	(53)
Depreciation and Amortization Expense	-	-	3	-	-
Interest Expense	911	755	(1,022)	(522)	621
Property, Plant and Equipment	(131)	(67)	(161)	(84)	(67)
Regulatory Assets (a)	869	128	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of September 30, 2011	$ 711	$ (12,517)	$ 9,766	$ 7,306	$ (13,838)

(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 as of September 30, 2012 and December 31, 2011 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
September 30, 2012

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ 925	$ -	$ 1,503	$ -	$ (362)	$ 1,823
I&M	622	-	1,032	20,465	(257)	(20,408)
OPCo	1,289	-	2,120	-	(524)	8,435
PSO	46	-	6	-	34	6,650
SWEPCo	43	-	6	-	34	(16,240)

Company	Expected to be Reclassified to Net Income During the Next Twelve Months		Maximum Term for Exposure to Variability of Future Cash Flows
	Commodity	Interest Rate and Foreign Currency	
	(in thousands)		(in months)
APCo	$ (278)	$ (1,013)	20
I&M	(202)	(1,316)	20
OPCo	(405)	1,359	20
PSO	36	759	15
SWEPCo	34	(2,369)	15

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
December 31, 2011

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency

			(in thousands)			
APCo	$ 431	$ -	$ 2,418	$ -	$ (1,309)	$ 1,024
I&M	277	-	1,523	10,637	(819)	(14,465)
OPCo	584	-	3,239	-	(1,748)	9,454
PSO	-	-	107	-	(69)	7,218
SWEPCo	-	3	97	19,143	(62)	(15,462)

Company	Expected to be Reclassified to Net Income During the Next Twelve Months	
	Commodity	Interest Rate and Foreign Currency
	(in thousands)	
APCo	$ (1,140)	$ (1,052)
I&M	(712)	(595)
OPCo	(1,518)	1,359
PSO	(70)	759
SWEPCo	(63)	(1,864)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed balance sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their 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. AEPSC, on behalf of the Registrant Subsidiaries, uses 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.

AEPSC, on behalf of the Registrant Subsidiaries, uses 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 the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements 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 competitive retail auction loads, the Registrant Subsidiaries are obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. The Registrant Subsidiaries have not experienced a downgrade below investment grade. The following tables represent: (a) the Registrant Subsidiaries' aggregate fair values of such derivative contracts, (b) the amount of collateral the Registrant Subsidiaries would have been required to post for all derivative and non-derivative contracts if credit ratings of the Registrant Subsidiaries had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of September 30, 2012 and December 31, 2011:

		September 30, 2012	
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 2,155	$ 4,301	$ 4,301
I&M	1,481	2,956	2,956
OPCo	3,042	6,070	6,070
PSO	-	1,288	885
SWEPCo	-	1,517	1,042

		December 31, 2011	
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities

	(in thousands)		
APCo	$ 10,007	$ 6,211	$ 6,211
I&M	6,418	3,983	3,983
OPCo	13,550	8,410	8,410
PSO	-	856	414
SWEPCo	-	1,128	522

As of September 30, 2012 and December 31, 2011, the Registrant Subsidiaries were not required to post any collateral.

In addition, a majority of the Registrant Subsidiaries' 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, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (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 posted by the Registrant Subsidiaries and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of September 30, 2012 and December 31, 2011:

	September 30, 2012		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
APCo	$ 64,466	$ 76	$ 33,019
I&M	64,767	52	43,156
OPCo	90,977	107	46,597
PSO	26	-	16
SWEPCo	30	-	19

	December 31, 2011		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
APCo	$ 76,868	$ 8,107	$ 27,603
I&M	59,936	5,200	28,339
OPCo	104,091	10,978	37,380
PSO	142	-	61
SWEPCo	19,322	-	19,220

8. 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. The AEP System's market risk oversight staff independently monitors its valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of AEPSC's Chief Operation Officer, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer.

For 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. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included 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, FTRs and counterparty credit risk 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. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

AEP utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the 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, Other Cash Deposits and Cash and Cash Equivalents 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. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. 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.

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 classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of September 30, 2012 and December 31, 2011 are summarized in the following table:

	September 30, 2012		December 31, 2011	
Company	Book Value	Fair Value	Book Value	Fair Value

	(in thousands)			
APCo	$ 3,702,283	$ 4,597,740	$ 3,726,251	$ 4,431,912
I&M	2,109,630	2,431,912	2,057,675	2,339,344
OPCo	3,860,242	4,589,998	4,054,148	4,665,739
PSO	949,884	1,187,155	947,364	1,123,306
SWEPCo	2,046,139	2,424,311	1,728,637	2,019,094

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 I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

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

I&M maintains 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 these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. 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 as of September 30, 2012 and December 31, 2011:

	September 30, 2012			December 31, 2011		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	$ 12,945	$ -	$ -	$ 18,229	$ -	$ -
Fixed Income Securities:						
United States Government	693,127	107,721	(612)	543,506	60,946	(547)
Corporate Debt	35,798	5,531	(1,435)	53,979	4,932	(1,536)
State and Local Government	226,142	1,301	(660)	329,986	(430)	(2,236)
Subtotal Fixed Income Securities	955,067	114,553	(2,707)	927,471	65,448	(4,319)
Equity Securities - Domestic	731,679	291,224	(77,662)	646,032	214,748	(79,536)
Spent Nuclear Fuel and						

Decommissioning Trusts	$ 1,699,691	$ 405,777	$ (80,369)	$ 1,591,732	$ 280,196	$ (83,855)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Proceeds from Investment Sales	$ 181,988	$ 361,001	$ 698,567	$ 825,689
Purchases of Investments	199,150	378,607	744,131	870,769
Gross Realized Gains on Investment Sales	2,046	17,256	6,978	29,661
Gross Realized Losses on Investment Sales	924	11,313	3,143	20,603

The adjusted cost of fixed income securities was $840 million and $862 million as of September 30, 2012 and December 31, 2011, respectively. The adjusted cost of equity securities was $441 million and $431 million as of September 30, 2012 and December 31, 2011, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2012 was as follows:

	Fair Value of Fixed Income Securities (in thousands)
Within 1 year	$ 136,610
1 year – 5 years	356,630
5 years – 10 years	265,125
After 10 years	196,702
Total	$ 955,067

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2012 and December 31, 2011. 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. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2012

APCo	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 4,301	$ 219,033	$ 23,357	$ (178,608)	$ 68,083
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,306	289	(670)	925
De-designated Risk Management Contracts (b)	-	-	-	590	590
Total Risk Management Assets	$ 4,301	$ 220,339	$ 23,646	$ (178,688)	$ 69,598
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 1,931	$ 209,732	$ 12,606	$ (186,641)	$ 37,628
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,173	-	(670)	1,503
Total Risk Management Liabilities	$ 1,931	$ 211,905	$ 12,606	$ (187,311)	$ 39,131

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

APCo	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 4,680	$ 302,128	$ 25,423	$ (255,324)	$ 76,907
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,095	-	(664)	431
De-designated Risk Management Contracts (b)	-	-	-	1,533	1,533
Total Risk Management Assets	$ 4,680	$ 303,223	$ 25,423	$ (254,455)	$ 78,871
Liabilities:					

	Risk Management Liabilities				
Risk Management Commodity Contracts (a) (f)	$ 2,535	$ 291,194	$ 23,379	$ (279,997)	$ 37,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,009	73	(664)	2,418
Total Risk Management Liabilities	$ 2,535	$ 294,203	$ 23,452	$ (280,661)	$ 39,529

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2012

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 2,955	$ 154,581	$ 16,051	$ (119,809)	$ 53,778
Cash Flow Hedges:					
Commodity Hedges (a)	-	880	198	(456)	622
De-designated Risk Management Contracts (b)	-	-	-	406	406
Total Risk Management Assets	2,955	155,461	16,249	(119,859)	54,806
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	-	4,995	-	7,950	12,945
Fixed Income Securities:					
United States Government	-	693,127	-	-	693,127
Corporate Debt	-	35,798	-	-	35,798
State and Local Government	-	226,142	-	-	226,142
Subtotal Fixed Income Securities	-	955,067	-	-	955,067
Equity Securities - Domestic (e)	731,679	-	-	-	731,679
Total Spent Nuclear Fuel and Decommissioning Trusts	731,679	960,062	-	7,950	1,699,691
Total Assets	$ 734,634	$ 1,115,523	$ 16,249	$ (111,909)	$ 1,754,497
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 1,327	$ 141,858	$ 8,663	$ (125,328)	$ 26,520
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,488	-	(456)	1,032
Interest Rate/Foreign Currency Hedges	-	20,465	-	-	20,465
Total Risk Management Liabilities	$ 1,327	$ 163,811	$ 8,663	$ (125,784)	$ 48,017

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 3,001	$ 203,175	$ 16,305	$ (162,227)	$ 60,254
Cash Flow Hedges:					
Commodity Hedges (a)	-	702	-	(425)	277
De-designated Risk Management Contracts (b)	-	-	-	983	983
Total Risk Management Assets	3,001	203,877	16,305	(161,669)	61,514
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	-	5,431	-	12,798	18,229
Fixed Income Securities:					
United States Government	-	543,506	-	-	543,506
Corporate Debt	-	53,979	-	-	53,979
State and Local Government	-	329,986	-	-	329,986
Subtotal Fixed Income Securities	-	927,471	-	-	927,471
Equity Securities - Domestic (e)	646,032	-	-	-	646,032
Total Spent Nuclear Fuel and Decommissioning Trusts	646,032	932,902	-	12,798	1,591,732
Total Assets	$ 649,033	$ 1,136,779	$ 16,305	$ (148,871)	$ 1,653,246
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 1,626	$ 185,092	$ 14,995	$ (178,022)	$ 23,691
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,901	47	(425)	1,523
Interest Rate/Foreign Currency Hedges	-	10,637	-	-	10,637
Total Risk Management Liabilities	$ 1,626	$ 197,630	$ 15,042	$ (178,447)	$ 35,851

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2012

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (c)	$ -	$ 26	$ -	$ 39	$ 65
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	6,069	318,501	32,962	(260,623)	96,909
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,824	407	(942)	1,289
De-designated Risk Management Contracts (b)	-	-	-	833	833
Total Risk Management Assets	6,069	320,325	33,369	(260,732)	99,031
Total Assets	$ 6,069	$ 320,351	$ 33,369	$ (260,693)	$ 99,096
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 2,726	$ 305,493	$ 17,790	$ (271,958)	$ 54,051
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,062	-	(942)	2,120
Total Risk Management Liabilities	$ 2,726	$ 308,555	$ 17,790	$ (272,900)	$ 56,171

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (c)	$ 26	$ -	$ -	$ 22	$ 48
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	6,339	421,249	34,425	(356,766)	105,247
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,483	-	(899)	584
De-designated Risk Management Contracts (b)	-	-	-	2,076	2,076
Total Risk Management Assets	6,339	422,732	34,425	(355,589)	107,907
Total Assets	$ 6,365	$ 422,732	$ 34,425	$ (355,567)	$ 107,955
Liabilities:					
Risk Management Liabilities					

Risk Management Commodity Contracts (a) (f)	$ 3,433	$ 406,259	$ 31,659	$ (390,139)	$ 51,212
Cash Flow Hedges:					
Commodity Hedges (a)	-	4,038	100	(899)	3,239
Total Risk Management Liabilities	$ 3,433	$ 410,297	$ 31,759	$ (391,038)	$ 54,451

197

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2012

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 8	$ 5,126	$ -	$ (4,511)	$ 623
Cash Flow Hedges:					
Commodity Hedges (a)	-	58	-	(12)	46
Total Risk Management Assets	$ 8	$ 5,184	$ -	$ (4,523)	$ 669
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 6	$ 10,625	$ -	$ (4,515)	$ 6,116
Cash Flow Hedges:					
Commodity Hedges (a)	-	18	-	(12)	6
Total Risk Management Liabilities	$ 6	$ 10,643	$ -	$ (4,527)	$ 6,122

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 97	$ 7,797	$ -	$ (7,015)	$ 879
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 53	$ 9,542	$ -	$ (7,092)	$ 2,503
Cash Flow Hedges:					
Commodity Hedges	-	107	-	-	107
Total Risk Management Liabilities	$ 53	$ 9,649	$ -	$ (7,092)	$ 2,610

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2012

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Cash and Cash Equivalents (c)	$ 14,108	$ -	$ -	$ 2,518	$ 16,626
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	9	8,303	-	(7,472)	840
Cash Flow Hedges:					
Commodity Hedges (a)	-	55	-	(12)	43
Total Risk Management Assets	9	8,358	-	(7,484)	883
Total Assets	$ 14,117	$ 8,358	$ -	$ (4,966)	$ 17,509
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 7	$ 11,744	$ -	$ (7,475)	$ 4,276
Cash Flow Hedges:					
Commodity Hedges (a)	-	18	-	(12)	6
Total Risk Management Liabilities	$ 7	$ 11,762	$ -	$ (7,487)	$ 4,282

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 122	$ 7,023	$ -	$ (6,421)	$ 724
Cash Flow Hedges:					
Interest Rate/Foreign Currency Hedges	-	3	-	-	3
Total Risk Management Assets	$ 122	$ 7,026	$ -	$ (6,421)	$ 727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 66	$ 11,753	$ -	$ (6,479)	$ 5,340
Cash Flow Hedges:					
Commodity Hedges	-	97	-	-	97
	-	19,143	-	-	19,143

Interest Rate/Foreign Currency Hedges						
Total Risk Management Liabilities	$ 66	$ 30,993	$ -	$ (6,479)	$ 24,580	

(a) 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."

(b) 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.

(c) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(d) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(e) Amounts represent publicly traded equity securities and equity-based mutual funds.

(f) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2012 and 2011.

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

Three Months Ended September 30, 2012	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of June 30, 2012	$ 12,864	$ 9,049	$ 18,969	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(3,540)	(2,440)	(5,024)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	(1,030)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	403	277	571	-	-
Purchases, Issuances and Settlements (c)	929	635	1,299	-	-
Transfers into Level 3 (d) (f)	654	460	964	-	-
Transfers out of Level 3 (e) (f)	(287)	(202)	(423)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	17	(193)	253	-	-
Balance as of September 30, 2012	$ 11,040	$ 7,586	$ 15,579	$ -	$ -

Three Months Ended September 30, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of June 30, 2011	$ 5,321	$ 3,150	$ 6,759	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4,553)	(2,904)	(6,138)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	(939)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(7)	(7)	(13)	-	-
Purchases, Issuances and Settlements (c)	358	297	599	-	-
Transfers into Level 3 (d) (f)	-	-	-	-	-
Transfers out of Level 3 (e) (f)	(259)	(154)	(330)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(91)	112	1,103	-	-
Balance as of September 30, 2011	$ 769	$ 494	$ 1,041	$ -	$ -

Nine Months Ended September 30, 2012	APCo	I&M	OPCo	PSO	SWEPCo

					(in thousands)					
Balance as of December 31, 2011	$	1,971	$	1,263	$	2,666	$	-	$	-
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(5,108)		(3,488)		(7,316)		-		-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-		-		4,973		-		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		312		211		435		-		-
Purchases, Issuances and Settlements (c)		10,605		7,325		15,375		-		-
Transfers into Level 3 (d) (f)		4,142		2,749		5,789		-		-
Transfers out of Level 3 (e) (f)		(4,910)		(3,193)		(6,733)		-		-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		4,028		2,719		390		-		-
Balance as of September 30, 2012	$	11,040	$	7,586	$	15,579	$	-	$	-

Nine Months Ended September 30, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2010	$ 5,131	$ 3,108	$ 6,583	$ 1	$ 2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,373)	(1,401)	(3,007)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	1,947	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(45)	(29)	(61)	-	-
Purchases, Issuances and Settlements (c)	2,835	1,656	3,567	-	-
Transfers into Level 3 (d) (f)	1,299	764	1,638	-	-
Transfers out of Level 3 (e) (f)	(3,057)	(1,834)	(3,908)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(3,021)	(1,770)	(5,718)	(1)	(2)
Balance as of September 30, 2011	$ 769	$ 494	$ 1,041	$ -	$ -

(a) Included in revenues on the 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 the condensed statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of September 30, 2012:

APCo	Fair Value		Valuation	Significant Unobservable Input	Forward Price Range	
	Assets	Liabilities	Technique	(a)	Low	High
	(in thousands)					
Energy Contracts	$ 21,300	$ 10,451	Discounted Cash Flow	Forward Market Price	$ 10.45	$ 63.25
FTRs	2,346	2,155	Discounted Cash Flow	Forward Market Price	(3.81)	9.92
Total	$ 23,646	$ 12,606				

I&M	Fair Value		Valuation	Significant Unobservable Input	Forward Price Range	
	Assets	Liabilities	Technique	(a)	Low	High
	(in thousands)					

Energy Contracts	$ 14,637	$ 7,182	Discounted Cash Flow	Forward Market Price	$ 10.45	$ 63.25
FTRs	1,612	1,481	Discounted Cash Flow	Forward Market Price	(3.81)	9.92
Total	$ 16,249	$ 8,663				

OPCo	Fair Value		Valuation	Significant Unobservable Input	Forward Price Range	
	Assets	Liabilities	Technique	(a)	Low	High
	(in thousands)					
Energy Contracts	$ 30,058	$ 14,748	Discounted Cash Flow	Forward Market Price	$ 10.45	$ 63.25
FTRs	3,311	3,042	Discounted Cash Flow	Forward Market Price	(3.81)	9.92
Total	$ 33,369	$ 17,790				

(a) Represents market prices in dollars per MWh.

9. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2009. The Registrant Subsidiaries 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 did not have a material impact on the Registrant Subsidiaries' 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, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material effect on net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000. In March 2012, AEP settled all outstanding franchise tax issues with the State of Ohio for the years 2000 through 2009. The settlements did not have a material impact on the Registrant Subsidiaries' net income, cash flows or financial condition.

Uncertain Tax Positions

The reconciliation of the beginning and ending amount of unrecognized tax benefits for OPCo as a result of the franchise tax settlement with the State of Ohio is as follows:

	OPCo
	(in thousands)
Balance as of December 31, 2011	$ 43,565
Increase - Tax Positions Taken During a Prior Period	-
Decrease - Tax Positions Taken During a Prior Period	(23,813)
Increase - Tax Positions Taken During the Current Year	-
Decrease - Tax Positions Taken During the Current Year	-
Decrease - Settlements with Taxing Authorities	(4,742)

Decrease - Lapse of the Applicable Statute of Limitations		-
Balance as of September 30, 2012	$	15,010

State Tax Legislation

During the third quarter of 2012, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not have a material impact on the Registrant Subsidiaries' net income, cash flows or financial condition.

10. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2012 are shown in the tables below:

Company Issuances:	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
APCo	Senior Unsecured Notes	$ 275,000	Variable	2013
APCo	Pollution Control Bonds	65,350	2.25	2016
I&M	Notes Payable	109,500	Variable	2016
I&M	Other Long-term Debt	20,000 (a)	Variable	2015
PSO	Notes Payable	2,395	3.00	2027
SWEPCo	Senior Unsecured Notes	275,000	3.55	2022
SWEPCo	Notes Payable	65,000	4.58	2032

(a) Consists of a $110 million three-year credit facility to be used for general corporate purposes.

Company Retirements and Principal Payments:	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
APCo	Pollution Control Bonds	$ 30,000	6.05	2024
APCo	Pollution Control Bonds	19,500	5.00	2021
APCo	Pollution Control Bonds	65,350	2.00	2012
APCo	Senior Unsecured Notes	250,000	5.65	2012
APCo	Land Note	18	13.718	2026
I&M	Notes Payable	13,860	5.44	2013
I&M	Notes Payable	10,590	4.00	2014
I&M	Notes Payable	15,353	Variable	2015
I&M	Notes Payable	17,924	Variable	2016
I&M	Notes Payable	12,414	2.12	2016
I&M	Notes Payable	7,552	Variable	2016
I&M	Other Long-term Debt	371	6.00	2025
OPCo	Pollution Control Bonds	44,500	4.85	2012
OPCo	Senior Unsecured Notes	150,000	Variable	2012

PSO	Notes Payable	130	3.00	2027
SWEPCo	Notes Payable	20,000	7.03	2012
SWEPCo	Notes Payable	1,625	4.58	2032

In October 2012, I&M retired $29 million of Notes Payable related to DCC Fuel.

As of September 30, 2012, trustees held, on behalf of OPCo, $463 million of its reacquired Pollution Control Bonds.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant 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. As applicable, management understands "capital account" to mean the book value of the common stock.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of their respective ownership of such plants, this reserve applies to APCo, I&M and OPCo.

None of these restrictions limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, APCo, I&M and OPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of the subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of September 30, 2012 and December 31, 2011 is included in Advances to/from Affiliates on each of the Registrant Subsidiaries' condensed balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the nine months ended September 30, 2012 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Net Loans (Borrowings) to/from Utility Money Pool as of September 30, 2012	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 350,153	$ 23,195	$ 168,094	$ 22,692	$ (94,807)	$ 600,000
I&M	-	362,733	-	208,072	284,768	500,000
OPCo	126,975	290,356	47,820	92,517	124,606	600,000
PSO	-	177,778	-	93,219	107,459	300,000
SWEPCo	227,087	128,227	147,338	62,312	128,227	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30,	
	2012	2011
Maximum Interest Rate	0.56 %	0.56 %
Minimum Interest Rate	0.44 %	0.06 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 30, 2012 and 2011 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from Utility Money Pool for Nine Months Ended September 30, 2012	2011	Average Interest Rate for Funds Loaned to Utility Money Pool for Nine Months Ended September 30, 2012	2011
APCo	0.48 %	0.38 %	0.48 %	0.31 %
I&M	- %	0.39 %	0.47 %	0.31 %
OPCo	0.47 %	0.45 %	0.50 %	0.31 %
PSO	- %	0.41 %	0.47 %	0.26 %
SWEPCo	0.53 %	0.34 %	0.47 %	0.33 %

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

Company	Type of Debt	September 30, 2012 Outstanding Amount (in thousands)	Interest Rate (a)	December 31, 2011 Outstanding Amount (in thousands)	Interest Rate (a)
SWEPCo	Line of Credit – Sabine	$ -	- %	$ 17,016	1.79 %

(a) Weighted average rate.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 3.

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' condensed statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

In June 2012, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of September 30, 2012 and December 31, 2011 was as follows:

Company	September 30, 2012	December 31, 2011
	(in thousands)	
APCo	$ 131,937	$ 121,605
I&M	116,702	121,597
OPCo	322,440	346,695
PSO	127,008	123,172
SWEPCo	160,802	140,440

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
		(in thousands)		
APCo	$ 1,703	$ 2,500	$ 5,389	$ 7,314
I&M	1,674	1,623	4,738	4,758
OPCo	5,362	5,585	15,900	14,025
PSO	1,990	2,081	5,547	4,798
SWEPCo	1,786	1,850	4,720	4,254

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

Company	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
		(in thousands)		
APCo	$ 351,570	$ 307,364	$ 993,975	$ 958,288
I&M	358,936	350,108	1,018,933	1,016,680
OPCo	790,115	956,909	2,284,749	2,699,782
PSO	342,819	436,339	919,343	1,021,967
SWEPCo	444,461	475,219	1,145,182	1,165,245

11. SUSTAINABLE COST REDUCTIONS

In April 2012, management initiated a process to identify employee repositioning opportunities and efficiencies that will result in sustainable cost savings. The process will result in involuntary severances and is expected to be completed in early 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The Registrant Subsidiaries recorded charges to expense in 2012 related to the sustainable cost reductions initiative.

	Expense Allocation from AEPSC	Incurred for Registrant Subsidiaries	Settled	Remaining Balance at September 30, 2012
		(in thousands)		
APCo	$ 2,076	$ 715	$ (2,780)	$ 11
I&M	1,231	277	(1,480)	28
OPCo	3,099	756	(3,827)	28
PSO	1,121	3	(1,124)	-
SWEPCo	1,367	898	(2,241)	24

These expenses relate primarily to severance benefits. They are included primarily in Other Operation on the condensed statements of income and Other Current Liabilities on the condensed balance sheets. At this time, management is unable to estimate the total amount to be incurred in future periods related to this initiative or to quantify the effects on future net income, cash flows and financial condition.

COMBINED MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (a) Management's Narrative Discussion and Analysis of Results of Operations, (b) financial statements, (c) footnotes and (d) the schedules of each individual registrant. The Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries section of the 2011 Annual Report should also be read in conjunction with this report.

EXECUTIVE OVERVIEW

Proposed Corporate Separation and Termination of the Interconnection Agreement

In March 2012, OPCo filed an application with the PUCO for approval of the corporate separation of its generation assets including the transfer of generation assets to a nonregulated AEP subsidiary at net book value. In October 2012, the PUCO issued an order which approved the transfer of OPCo's generation assets at net book value to AEP Generation Resources, Inc. (AEPGenCo), a nonregulated affiliate in the Generation and Marketing segment. AEPGenCo will also assume the associated generation liabilities. Management intends to file an application with the FERC in the fourth quarter of 2012 related to corporate separation. Prior to corporate separation, OPCo's results of operations related to generation could be affected by the ability to sell power and capacity at a profit at rates determined by the prevailing market. If power and capacity are not sold at a profit, it could reduce OPCo's future net income and cash flows and impact financial condition

In December 2010, each of the members of the Interconnection Agreement gave notice to AEPSC and each other of its decision to terminate the Interconnection Agreement effective as of December 31, 2013 or such other date as ordered by the FERC. Management intends to file an application with the FERC in the fourth quarter of 2012 to terminate the Interconnection Agreement. It is unknown whether the Interconnection Agreement 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. If any of the members of the Interconnection Agreement experience decreases in revenues or increases in costs as a result of the termination of the Interconnection Agreement 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.

Based on the interdependent nature of generation activities subject to the Interconnection Agreement, the AEP East companies' generation assets are evaluated for their accounting recoverability collectively as an asset group. Management is monitoring the potential impact that the proposed corporate separation of OPCo's generation assets and the proposed termination of the Interconnection Agreement could have on the accounting evaluation of the recoverability of the net book values of OPCo's generation assets. The net book value of the OPCo units that management plans to retire included in the table below in the "Environmental Controls Impact on the Generating Fleet" section and OPCo's share of the W. C. Beckjord Generating Station was $284 million as of September 30, 2012. These generating assets are being depreciated through May 2015.

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The Registrant Subsidiaries 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.

The Registrant Subsidiaries 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 I&M's nuclear units. Management is 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, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. 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. Management believes that further analysis and better coordination of these 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 "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2011 Annual Report. Management will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. The Registrant Subsidiaries should be able to recover certain of these expenditures through market prices in deregulated jurisdictions. If not, the costs of environmental compliance could reduce future net income and cash flows and impact financial condition.

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. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2012, the AEP System had a total generating capacity of 37,035 MWs, of which 23,900 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the coal-fired generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these proposed requirements are listed below:

	2012 to 2020 Estimated Environmental Investment	
Company	Low	High
	(in millions)	
APCo	$ 415	$ 515
I&M	1,490	1,710
OPCo	1,260	1,510
PSO	430	530
SWEPCo	1,250	1,450

For APCo and OPCo, the projected environmental investments above include the conversion of 470 MWs and 585 MWs, respectively, of coal generation to natural gas-fired generation. If natural gas conversion is not completed, the units could be closed sooner than planned.

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 for each Registrant Subsidiary 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 more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the 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 continuing evaluation, management has given notice to the applicable RTOs of the intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
OPCo	Conesville Plant, Unit 3	165
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528

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

In September 2012, based upon an agreement in principle with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC to retire Units 3 and 4 of the Northeastern Station, a total of 930 MWs, in 2026 and 2016, respectively. See “Oklahoma Environmental Compliance Plan” and “Regional Haze” sections below.

Natural gas prices and pending environmental rules could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of certain coal-fired units. Management is still evaluating plans for and the timing of conversion of some of the coal units to natural gas, installing emission control equipment on other units and closure of existing units based on changes in emission requirements and demand for power. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable under the accounting evaluations, it could materially reduce future net income and cash flows.

Environmental Compliance Applications

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of

September 30, 2012, I&M has incurred $24 million, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

In July 2012, certain intervenors filed testimony which recommended cost caps ranging from $1.1 billion to $1.4 billion if the IURC approved the CPCN. In addition, the Indiana Office of Utility Consumer Counselor recommended the CPCN be denied until a more detailed project plan and cost estimates are filed with the IURC. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. A hearing is scheduled for December 2012.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. Through September 30, 2012, SWEPCo has incurred $10 million related to this project, including AFUDC. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing at the APSC was held in October 2012 and a decision is pending from the APSC. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC which requested approval for (a) full cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at Northeastern Station Unit 3, (b) full cost recovery through 2026 of Northeastern Station Units 3 and 4 net book value (combined net book value of the two units is $235 million as of September 30, 2012), (c) full cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement with Calpine Oneta Power, effective in 2016, with cost recovery through a rider, including an earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the Cross-State Air Pollution Rule (CSAPR) trading programs to use those programs in place of source-specific BART for SO2 and NOx emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the United States Court of Appeals for the District of Columbia Circuit and its fate is uncertain given recent developments in the CSAPR litigation.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO2, NOx and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting the Registrant Subsidiaries' operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR 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. Arkansas and Louisiana are subject only to the seasonal NOx program in the rule. Texas is 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 were reduced significantly in the final rule. A supplemental rule includes Oklahoma in the seasonal NOx program. The supplemental rule was finalized in December 2011 with an increased NOx emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents have filed petitions for rehearing. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance until the court responds to the rehearing petition in the main CSAPR appeal.

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 its electric utility customers. Management cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In February 2012, the Federal EPA issued 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. The effective date of the final rule was April 16, 2012 and compliance is required within three years. The AEP System is participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In July 2012, the Federal EPA issued a letter announcing that it will grant petitions for administrative reconsideration of certain issues related to the new source standards, including measurement issues and application of variability factors that may have an impact on the level of the standards. The letter also announced a three-month stay in the effective date of the new source standards. It is uncertain whether any of the information generated during the reconsideration process will affect the standards for existing sources.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. Management is concerned

about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. The AEP System is participating in petitions for review filed in the United States Court of Appeals for the District of Columbia Circuit by several organizations in which the Registrant Subsidiaries are members. Certain issues related to the standards for new coal-fired units have been severed from the main case. The Federal EPA granted petitions to reconsider certain issues related to the new source standards. Action by the court on these severed issues is being held in abeyance pending action on those petitions. The case is proceeding on the remaining issues and briefing is scheduled to be completed by April 2013.

Regional Haze – Affecting PSO

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed 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 proposed a 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. 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. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In April 2012, an agreement in principle was reached that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The parties are working toward finalizing a settlement agreement which is intended to allow PSO to meet its compliance obligations under the regional haze and HAPs rules.

CO2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources, and does not apply to units whose CO2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction, like SWEPCo's Turk Plant. The comment period closed in June 2012. New Source Performance Standards affect units that have not yet received permits, but complete the permitting process while the proposal is pending. The standards have been challenged in the United States Court of Appeals for the District of Columbia Circuit. Management cannot predict the outcome of that litigation.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO2 emissions from new motor vehicles and its plan to phase in regulation of CO2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed and the court ordered the Federal EPA to respond in October 2012. The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. The AEP System's generating units are large sources of CO2 emissions and management will continue to evaluate the permitting obligations in light of these thresholds.

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 the 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. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash.

Currently, approximately 40% of the coal ash and other residual products from the AEP System's 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, surface impoundments and landfills to manage these materials are currently used at the generating facilities. The Registrant Subsidiaries will incur significant costs to upgrade or close and replace their existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, management is unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

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 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. Management is evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at the AEP System's facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. Management submitted comments in July 2012. Issuance of a final rule is not expected until July 2013. Management is preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

Global Warming

National public policy makers and regulators in the 10 states the Registrant Subsidiaries serve have conflicting views on global warming. While comprehensive economy-wide regulation of CO2 emissions might be achieved through future 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.

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 the Registrant Subsidiaries have generating facilities. Certain states, including Michigan, Ohio, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. Management is 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. The Registrant Subsidiaries have been named in pending lawsuits, which management is defending. It is not possible to predict the outcome of these lawsuits or their impact on operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 3.

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 the Registrant Subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could reduce future net income and cash flows and impact financial condition.

For additional information on global warming, other environmental issues and the actions management is taking to address potential impacts, see Part I of the 2011 Form 10-K under the headings entitled "Business – General – Environmental and Other Matters" and "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries."

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

Item 4. Controls and Procedures

During the third quarter of 2012, management, including the principal executive officer and principal financial officer of each of AEP, APCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of September 30, 2012, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2012 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

214

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see "Commitments, Guarantees and Contingencies," of Note 3 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2011 includes a detailed discussion of risk factors. The information presented below amends certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in the 2011 Annual Report on Form 10-K.

GENERAL RISKS OF OUR REGULATED OPERATIONS

We may not fully recover all of the investment in and expenses related to the Turk Plant – Affecting AEP and SWEPCo

SWEPCo is currently constructing the Turk Plant in Arkansas and holds a 73% ownership interest in the planned 600 MW coal-fired generating facility. 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. SWEPCo announced that it would continue construction of the Turk Plant and would not currently seek authority to serve Arkansas retail customers from the Turk Plant. In June 2010, the APSC reversed and set aside the previously granted CECPN. SWEPCo currently has no contracts for the 88 MW of Turk Plant output but is evaluating its options. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could materially reduce future net income and cash flows and materially impact financial condition.

Approval of ESP order in Ohio may be overturned on rehearing. – Affecting AEP and OPCo

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. In September 2012, OPCo and intervenors filed applications with the PUCO for rehearing. Rehearing of this order is pending at the PUCO. If the PUCO reverses all or part of the ESP order, it could reduce future net income and cash flows and impact financial condition.

We may not fully collect deferred capacity costs. – Affecting AEP and OPCo

The PUCO adopted and modified the new ESP and established a non-bypassable Retail Stability Rider (RSR). A portion of the RSR provides for the collection of deferred capacity costs. The deferred capacity costs may exceed the amount we will collect under the RSR. In addition, the Industrial Energy Users-Ohio filed a claim before the Supreme Court of Ohio stating, among other things, that OPCo's recovery of its capacity costs is illegal. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition.

We may not recover deferred fuel costs. – Affecting AEP and OPCo

In August 2012, the PUCO ordered recovery of deferred fuel costs beginning September 2012 through the Phase-In Recovery Rider. The August 2012 order was upheld by the PUCO in October 2012. OPCo and intervenors may file appeals at the Supreme Court of Ohio. No filings at the Supreme Court of Ohio have been made at this time. If appeals are filed and the Supreme Court of Ohio does not permit full recovery of OPCo's deferred fuel costs, it would

reduce future net income and cash flows and impact financial condition.

Rate recovery approved in Ohio may have to be returned and/or may not provide full recovery of costs. – Affecting AEP and OPCo

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates through 2011. The ESP order generally authorized rate increases during the ESP period, subject to caps that limit the rate increases, and also provided a fuel adjustment clause for the three-year period of the ESP. The recovery under the fuel adjustment clause included deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. In January 2011, the PUCO issued an order on the 2009 SEET filing, which is currently under appeal at the Supreme Court of Ohio. In July 2011, OPCo filed its 2010 SEET filing with the PUCO. OPCo is required to file its 2011 SEET filing with the PUCO in 2012 on a separate CSPCo and OPCo company basis. In addition, intervenors are challenging various issues at the Supreme Court of Ohio, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge. If the PUCO and/or the Supreme Court of Ohio reverses all or part of the rate recovery or if deferred fuel costs are not recovered for other reasons, it could reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund additional fuel costs. – Affecting AEP and OPCo

In January 2012, the PUCO ordered that proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. Further, the January 2012 PUCO order stated that a consultant be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of the consultant's recommendation. In addition, an intervenor filed a claim for refund with the Supreme Court of Ohio. If the PUCO and/or the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

The PUCO-selected outside consultant issued its results of the 2010 and 2011 FAC audit. The audit reports included recommendations that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Request for rate recovery in Indiana may not be approved in its entirety. – Affecting AEP and I&M

In September 2011, I&M filed a request with the IURC for annual increases in Indiana base rates. If the IURC denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Request for rate recovery in Texas may not be approved in its entirety. – Affecting AEP and SWEPCo

In July 2012, SWEPCo filed a request with the PUCT for an annual increase in Texas base rates. If the PUCT denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

RISKS RELATING TO STATE RESTRUCTURING

We are unable to fully predict the effects of corporate separation in Ohio and becoming subject to market forces. – Affecting AEP and OPCo

In October 2012, the PUCO approved OPCo's corporate separation plan for its generation assets. Additional filings at the FERC and other state commissions related to corporate separation are expected to be filed in the fourth quarter of 2012. If all regulatory approvals are received, our results of operations related to generation in Ohio will be largely determined by our ability to sell power and capacity at a profit at rates determined by the prevailing market. If we are

unable to sell power and capacity at a profit, it could reduce future net income and cash flows and impact financial condition. We can give no assurance that the FERC or other state commissions will not impose material adverse terms as a condition to approving our corporate separation. Additionally, certain of our generation units may no longer be cost effective and may be retired prior to the end of their anticipated useful life. This could result in material impairments.

We are unable to predict the consequences of terminating the Interconnection Agreement. – Affecting AEP, APCo, I&M and OPCo

The corporate separation plans of OPCo's generation assets will require us to either terminate or substantially alter the Interconnection Agreement. The Interconnection Agreement permits AEP East companies to share costs and benefits associated with their generating plants on a cost basis. It is unknown whether the Interconnection Agreement 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. If the Interconnection Agreement is terminated without any subsequent agreements between some or all of the parties, surplus members will no longer automatically sell to deficit members, and they may not be able to otherwise sell that surplus in amounts or at rates equal to what they obtained under the Interconnection Agreement. Conversely, deficit members will no longer automatically purchase from surplus members, and they may not be able to otherwise purchase in amounts or at rates equal to what they obtained under the Interconnection Agreement. The possible loss of these sales by the surplus members and the potential increase in costs for the deficit members could reduce future net income and cash flows. We intend to file an application with the FERC to terminate the Interconnection Agreement in the fourth quarter of 2012. We can give no assurance that the FERC will not impose material adverse terms as a condition to approving these arrangements.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. – Affecting each Registrant

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was signed into law. The federal legislation was enacted to reform financial markets and significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including: (a) imposing pervasive regulation by the Commodity Futures Trading Commission (CFTC) on dealers and traders who hold significant positions in swaps, (b) requiring standardized OTC derivatives to be traded on registered exchanges as directed by CFTC, (c) imposing new and potentially higher capital and margin requirements on swap dealers and traders who hold significant positions in swaps and (d) increasing the monitoring and compliance obligations of parties who engage in swaps with governmental entities. The CFTC has issued regulations exempting end users of energy commodities from being required to clear OTC derivatives if they are hedging commercial risk and satisfying certain other requirements, which could reduce the effect of the law's clearing requirements on our hedging activity. The CFTC has also issued rules that further define the OTC derivative products and entities subject to additional regulatory oversight, which recently became effective. These requirements could subject us to additional regulatory oversight related to our OTC derivative transactions, cause our OTC derivative transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to manage.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

NONE

Item 4. Mine Safety Disclosures

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, and OPCo, through its ownership of Conesville Coal Preparation

Company (CCPC) and 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 and its related regulations require companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 contains the notices of violation and proposed assessments received by DHLC, CCPC and Conner Run under the Mine Act for the quarter ended September 30, 2012.

Item 5. Other Information

NONE

Item 6. Exhibits

10 – AEP Long-Term Incentive Plan Amended and Restated as of September 25, 2012

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

95 – Mine Safety Disclosures

101.INS – XBRL Instance Document
101.SCH – XBRL Taxonomy Extension Schema
101.CAL – XBRL Taxonomy Extension Calculation Linkbase
101.DEF – XBRL Taxonomy Extension Definition Linkbase
101.LAB – XBRL Taxonomy Extension Label Linkbase
101.PRE – XBRL Taxonomy Extension Presentation Linkbase

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 26, 2012