AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 27, 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 June 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)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

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

Yes X No

Indicate by check mark whether 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.

X Accelerated filer

Large 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 July 26, 2012
American Electric Power Company, Inc.	484,902,556
	($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
June 30, 2012

Part II. OTHER INFORMATION

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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, 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.

Term	Meaning
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.
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.

Term	Meaning
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.
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 recent storms in our eastern service territory, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, and transmission 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.
- 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.
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Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- Volatility and changes in markets for electricity, 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.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate or amend the Interconnection Agreement.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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

Proposed June 2012 – May 2015 Ohio ESP

In March 2012, OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing. The SSO rates would be effective through May 2015. The ESP will transition OPCo to an auction-based SSO for capacity and energy by June 2015. The ESP also proposed to collect the Phase-In Recovery Rider from June 2013 through December 2018. Further, the ESP proposed establishment of a non-bypassable Distribution Investment Rider through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The filing also seeks establishment of a new non-bypassable Retail Stability Rider (RSR) to recover lost generation revenues to provide financial certainty and stability during the ESP transition period. The proposed RSR would be effective through May 2015. Finally, the ESP proposed a storm damage recovery mechanism for the deferral of operation and maintenance costs above $5 million, effective January 2012.

Intervenors and the PUCO staff filed testimony in May 2012 in opposition to many aspects of OPCo's ESP, including the proposed RSR and the two-tiered capacity pricing structure for CRES providers. In addition, the PUCO staff's testimony included a proposal to increase the vegetation management base used for calculating over/under recovery on incremental vegetation spend from $21 million to $39 million, which could increase future Other Operation and Maintenance expense by $18 million on an annual basis. A decision from the PUCO is expected in August 2012. 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 second quarter of 2011 and the first six months of 2011, we lost approximately $56 million and $99 million, respectively, of gross margin. We are recovering a portion of lost margins through collection of capacity revenues from CRES providers, off-system sales and new revenues from AEP Retail Energy Partners LLC, our CRES provider and member of our Generating and Marketing segment. We have lost 34% of our Ohio load to CRES providers. To enhance our competitive position in Ohio, AEP Retail Energy Partners LLC targets retail customers, both within and outside of our retail service territory.

Ohio Capacity Rate

In March 2012, in response to OPCo's motion for relief, the PUCO ordered that CRES providers not qualifying for the tier one capacity billing rate of $146/MW day, which is substantially below OPCo's current capacity cost of approximately $355/MW day, will pay a tier two capacity billing rate of $255/MW day. In July 2012, the PUCO issued an order in the capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer 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 pending June 2012 – May 2015 ESP proceeding. The PUCO postponed implementation of the order until August 8, 2012 or until an order is issued in OPCo's pending June 2012 – May 2015 ESP proceeding, whichever is sooner. In July 2012, OPCo requested rehearing of the PUCO order. See "Ohio Electric Security Plan Filing" section of Note 2.

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. Additional filings at the FERC and other state commissions related to corporate separation are expected to be filed in the future. If all regulatory approvals are received, our results of operations related to generation in Ohio will be 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. A decision is pending from the PUCO.

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. It is unknown at this time 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. Management intends to file an application to terminate the Interconnection Agreement with the FERC in the future. 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.

Sustainable Cost Reductions

In April 2012, we initiated a process to identify employee repositioning opportunities and efficiencies that will result in sustainable cost savings. We recorded a charge to expense of $13 million in the second quarter of 2012 related to the elimination of approximately 170 positions in the first phase of this process. In May 2012, we selected one consulting firm to conduct an organizational and process optimization evaluation and a second consulting firm to evaluate our current employee benefit programs. The second phase of this process is expected to be completed by the end of 2012 with additional cost reductions.

Storm Damage

In late June 2012 and early July 2012, our eastern service territory was significantly impacted by several severe storms. In the second quarter of 2012, AEP recorded minimal incremental operation and maintenance expenses related to the June 2012 storms. AEP expects to incur an estimated $230 million in total storm restoration costs in the third quarter of 2012, including an estimated $70 million in capital spending related to these storms and an estimated $160 million in incremental operation and maintenance costs. We intend to defer the majority of the incremental operation and maintenance costs and seek future recovery. If we are not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

Significantly Excessive Earnings Test

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off of certain pretax earnings in 2010 and a subsequent refund to customers during 2011. In May 2011, the Industrial Energy Users-Ohio and the Ohio Energy Group (OEG) 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 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 on July 31, 2012 or one month after the PUCO issues an order on the 2010 SEET, whichever is later. 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.

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 a $25 million increase in annual depreciation expense.

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 includes a return on and of the Texas jurisdictional share of Turk Plant generation investment at December 2011 and total estimated transmission costs of the Turk Plant along with associated costs, including operations and maintenance costs. It also proposed vegetation management expenditures and includes recovery of the Stall Unit.

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. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. 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 tightening oversight of nuclear generating facilities. We are unable to predict the impact of potential future regulation of nuclear facilities.

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.

3

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 Public Convenience and Necessity and authorize I&M to defer, on an interim basis, incremental depreciation and property tax costs, including interest, along with study, analysis and development costs until the applicable costs are included in I&M's base rates. As of June 30, 2012, I&M has incurred $92 million related to the LCM Project. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

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 June 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.

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.

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 recoverability of OPCo's generation assets.

In April 2012, we reached an agreement in principle with the Federal EPA, the State of Oklahoma and other parties to retire one coal-fired unit of PSO's Northeastern Station no later than 2016, install emission controls on the second coal-fired Northeastern unit in 2016 and retire the second unit no later than 2026. These two coal-fired units have a combined generating capacity of 930 MWs. The parties are working toward a final settlement agreement.

Plans for and the timing of conversion of some of our coal units to natural gas, installing emission control equipment on other units and closure of existing units will be impacted by changes in emission requirements and demand for power. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Environmental Control Applications

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 June 30, 2012, AEGCo and I&M have incurred $10 million and $10 million, respectively, related to this project.

5

In July 2012, certain intervenors filed testimony which recommended costs 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 and precise 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. An IURC decision is expected in the fourth quarter of 2012.

Big Sandy Unit 2 FGD System

In May 2012, KPCo filed a motion with the KPSC to withdraw its application seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system. The motion was accepted by the KPSC in May 2012. KPCo is currently re-evaluating its needs to meet the short and long-term energy needs of its customers at the most reasonable costs. KPCo has not determined its future plan. As of June 30, 2012, KPCo has incurred $29 million related to the project. Management intends to pursue recovery of all costs related to this project. If KPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Flint Creek Plant

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 June 30, 2012, SWEPCo has incurred $9 million related to this project. In June 2012, the APSC staff and the Arkansas Attorney General's office filed testimony that recommended additional analysis be performed in order to reach a final conclusion. The Sierra Club filed testimony that recommended the APSC deny the declaratory order. SWEPCo is currently reviewing the testimony and will file rebuttal testimony on July 30, 2012. A decision is pending from the APSC.

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 how 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. No action has been finalized in Arkansas. 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. As a result, depending on how the states decide to implement the CAVR, compliance with the CSAPR requirements may be sufficient to satisfy CAVR's BART requirements without the need for additional unit-specific controls.

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 beginning in 2012. 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 have been reduced significantly in the rule. 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. Oral argument was heard in April 2012. 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. A separate appeal of the supplemental rule has been filed, but is being held in abeyance until the court issues a decision in the main CSAPR appeal. 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. Challenges to these rules have also been filed, but are being held in abeyance pending a decision in the main 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 and will be considered by the court on an expedited basis. The Federal EPA’s grant of certain reconsideration petitions may alter this schedule.

7

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 source under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. 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.

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 CO_2 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 CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are 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 CO_2 would result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could 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 that were established in 2009 and our 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 Net Income by segment for the three and six months ended June 30, 2012 and 2011. We reclassified prior year amounts to conform to the current year's presentation.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Utility Operations	$365	$350	$749	$724
Transmission Operations	8	6	17	10
AEP River Operations	3	(1)	12	6
Generation and Marketing	(5)	11	(6)	12
All Other (a)	(8)	(13)	(19)	(44)
Net Income	$363	$353	$753	$708

(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

Second Quarter of 2012 Compared to Second Quarter of 2011

Net Income increased from $353 million in 2011 to $363 million in 2012 primarily due to:

- A decrease in other operation and maintenance expenses as a result of reduced spending.
- 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.

These increases were partially offset by:

- The loss of retail customers in Ohio to various CRES providers.
- A net decrease in regulated revenue primarily due to the elimination of POLR charges in Ohio effective June 2011, resulting from an October 2011 PUCO remand order.
- The increase in depreciation expenses as a result of shortened depreciable lives for certain OPCo generating plants and increases in depreciation rates for APCo and I&M in February 2012 (Virginia) and April 2012 (Michigan), respectively.

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

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Net Income increased from $708 million in 2011 to $753 million in 2012 primarily due to:

- A decrease in other operation and maintenance expenses as a result of reduced spending.
- 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 first quarter 2011 settlement of litigation with BOA and Enron.
- 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.

These increases were partially offset by:

- The loss of retail customers in Ohio to various CRES providers.
- A decrease in weather-related usage, primarily due to a decrease in heating degree days in the first quarter of 2012.
- A net decrease in regulated revenue primarily due to the elimination of POLR charges in Ohio effective June 2011, resulting from an October 2011 PUCO remand order.
- The increase in depreciation expenses as a result of shortened depreciable lives for certain OPCo generating plants and increases in depreciation rates for APCo and I&M in February 2012 (Virginia) and April 2012 (Michigan), respectively.

Average basic shares outstanding increased from 482 million in 2011 to 484 million in 2012. Actual shares outstanding were 485 million as of June 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Revenues	$3,258	$3,388	$6,643	$6,912
Fuel and Purchased Electricity	1,096	1,230	2,365	2,527
Gross Margin	2,162	2,158	4,278	4,385
Other Operation and Maintenance	770	852	1,525	1,702
Depreciation and Amortization	448	398	860	791
Taxes Other Than Income Taxes	202	199	413	408
Operating Income	742	709	1,480	1,484
Interest and Investment Income	2	2	3	4
Carrying Costs Income	11	17	31	32
Allowance for Equity Funds Used During Construction	20	22	40	42
Interest Expense	(224)	(227)	(441)	(459)
Income Before Income Tax Expense and Equity Earnings	551	523	1,113	1,103
Income Tax Expense	186	173	365	380
Equity Earnings of Unconsolidated Subsidiaries	-	-	1	1
Net Income	$365	$350	$749	$724

Summary of KWH Energy Sales for Utility Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions of KWHs)			
Retail:				
Residential	13,155	13,503	27,954	30,452
Commercial	13,087	12,913	24,353	24,559
Industrial	15,422	15,153	30,069	29,482
Miscellaneous	779	777	1,500	1,500
Total Retail (a)	42,443	42,346	83,876	85,993
Wholesale	8,620	10,216	17,533	19,367
Total KWHs	51,063	52,562	101,409	105,360

(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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in degree days)			
Eastern Region				
Actual - Heating (a)	118	134	1,379	1,989
Normal - Heating (b)	165	168	1,916	1,907
Actual - Cooling (c)	401	368	429	371
Normal - Cooling (b)	300	295	303	299
Western Region				
Actual - Heating (a)	1	10	348	702
Normal - Heating (b)	20	21	601	600
Actual - Cooling (d)	961	1,035	1,094	1,144
Normal - Cooling (b)	774	762	834	820

(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.

14

Second Quarter of 2012 Compared to Second Quarter of 2011

Reconciliation of Second Quarter of 2011 to Second Quarter of 2012
Net Income from Utility Operations
(in millions)

Second Quarter of 2011	$	350
Changes in Gross Margin:		
Retail Margins		(15)
Off-system Sales		5
Transmission Revenues		22
Other Revenues		(8)
Total Change in Gross Margin		4
Changes in Expenses and Other:		
Other Operation and Maintenance		82
Depreciation and Amortization		(50)
Taxes Other Than Income Taxes		(3)
Carrying Costs Income		(6)
Allowance for Equity Funds Used During Construction		(2)
Interest Expense		3
Total Change in Expenses and Other		24
Income Tax Expense		(13)
Second Quarter of 2012	$	365

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 decreased $15 million primarily due to the following:
  - A $70 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 $13 million net decrease in regulated revenue primarily due to the elimination of POLR charges in Ohio effective June 2011, resulting from an October 2011 PUCO remand order.

  These decreases were partially offset by:
  - A $35 million increase due to OPCo's partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
  - A $21 million 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.
  - A $9 million rate increase for APCo.
- Margins from Off-system Sales increased $5 million primarily due to higher PJM capacity revenues, partially offset by lower physical sales volumes and lower trading and marketing margins.
-

Transmission Revenues increased $22 million primarily due to net increases in ERCOT and increased transmission revenues for Ohio 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.

- Other Revenues decreased $8 million primarily due to a decrease in gains on other miscellaneous sales.

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

- Other Operation and Maintenance expenses decreased $82 million primarily due to the following:
  - A $46 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $30 million decrease in employee-related expenses and other reduced spending.
  - A $19 million decrease in storm expenses.

  These decreases were partially offset by:
  - A $13 million increase due to expenses related to the 2012 sustainable cost reductions.
- Depreciation and Amortization expenses increased $50 million primarily due to the following:
  - An $18 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.
  - An $18 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011.
  - A $14 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.
  - A $5 million increase in amortization primarily as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - 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 $5 million decrease in OPCo's depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.
- Carrying Costs Income decreased $6 million primarily due to OPCo's 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.
- Income Tax Expense increased $13 million primarily due to an increase in pre-tax book income.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Reconciliation of Six Months Ended June 30, 2011 to Six Months Ended June 30, 2012
Net Income from Utility Operations
(in millions)

Six Months Ended June 30, 2011	$	724
Changes in Gross Margin:		
Retail Margins		(113)
Off-system Sales		2
Transmission Revenues		34
Other Revenues		(30)
Total Change in Gross Margin		(107)
Changes in Expenses and Other:		
Other Operation and Maintenance		177
Depreciation and Amortization		(69)
Taxes Other Than Income Taxes		(5)
Interest and Investment Income		(1)
Carrying Costs Income		(1)
Allowance for Equity Funds Used During Construction		(2)
Interest Expense		18
Total Change in Expenses and Other		117
Income Tax Expense		15
Six Months Ended June 30, 2012	$	749

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 $113 million primarily due to the following:
  - A $124 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.
  - An $89 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 31% and 50%, respectively, in heating degree days.
  - A $17 million net decrease in regulated revenue primarily due to the elimination of POLR charges in Ohio effective June 2011, resulting from an October 2011 PUCO remand order.

  These decreases were partially offset by:
  - Successful rate proceedings in our service territories which include:
    - A $31 million rate increase for APCo.
    - A $14 million rate increase for I&M.
    - A $9 million rate increase for PSO.

    For the rate increases described above, $46 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 $24 million 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.

- Margins from Off-system Sales increased $2 million primarily due to higher PJM capacity revenues, partially offset by lower physical sales volumes and lower trading and marketing margins.
- Transmission Revenues increased $34 million primarily due to net increases in ERCOT and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.
- Other Revenues decreased $30 million primarily due to an unfavorable regulatory order in Ohio and a decrease in gains on other miscellaneous sales.

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

- Other Operation and Maintenance expenses decreased $177 million primarily due to the following:
  - A $75 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $75 million decrease in employee-related expenses and other reduced spending.
  - 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 $35 million decrease due to 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 $16 million decrease in other storm expenses.

  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 $13 million increase due to expenses related to the 2012 sustainable cost reductions.
  - An $8 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
- Depreciation and Amortization expenses increased $69 million primarily due to the following:
  - A $32 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011.
  - A $23 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 $21 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.
  - A $9 million increase in amortization primarily as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $19 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $10 million decrease in OPCo's depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.
- Carrying Costs Income decreased $1 million primarily due to the following:
  - A $6 million decrease due to OPCo's collection of carrying costs in the first quarter 2012 on phase-in FAC deferrals and line extension carrying charges recorded in 2011.
  - A $5 million decrease for OPCo due to a 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.
  - A $3 million increase from carrying charges on APCo's Dresden Plant resulting from the Virginia Generation Rate Adjustment Clause and the West Virginia Expanded Net Energy Charge.
- Interest Expense decreased $18 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense decreased $15 million primarily due to audit settlements for previous years and federal income tax adjustments recorded in 2011 related to prior year tax returns, partially offset by an increase in pre-tax book income.

TRANSMISSION OPERATIONS

Second Quarter of 2012 Compared to Second Quarter of 2011

Net Income from our Transmission Operations segment increased from $6 million in 2011 to $8 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Net Income from our Transmission Operations segment increased from $10 million in 2011 to $17 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

Second Quarter of 2012 Compared to Second Quarter of 2011

Net Income from our AEP River Operations segment increased from a loss of $1 million in 2011 to a gain of $3 million in 2012 primarily due to flood-related expenses incurred in the second quarter of 2011 and reduced spending in 2012.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Net Income from our AEP River Operations segment increased from $6 million in 2011 to $12 million in 2012 primarily due to flood-related expenses incurred in the second quarter of 2011 and reduced spending in 2012.

GENERATION AND MARKETING

Second Quarter of 2012 Compared to Second Quarter of 2011

Net Income from our Generation and Marketing segment decreased from a gain of $11 million in 2011 to a loss of $5 million in 2012 primarily due to the expiration of wind-related production tax credits in 2011, lower trading margins and reduced inception gains from ERCOT marketing activities.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Net Income from our Generation and Marketing segment decreased from a gain of $12 million in 2011 to a loss of $6 million in 2012 primarily due to the expiration of wind-related production tax credits in 2011 and lower trading margins.

ALL OTHER

Second Quarter of 2012 Compared to Second Quarter of 2011

Net Income from All Other increased from a loss of $13 million in 2011 to a loss of $8 million in 2012 primarily due to a decrease in various parent related expenses.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Net Income from All Other increased from a loss of $44 million in 2011 to a loss of $19 million in 2012 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

Second Quarter of 2012 Compared to Second Quarter of 2011

Income Tax Expense increased $16 million primarily due to an increase in pretax book income and the expiration of wind production tax credits in 2011.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Income Tax Expense decreased $73 million primarily due to the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, audit settlements for previous years and a decrease in pretax book income.

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

	June 30, 2012		December 31, 2011	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 17,302	51.6 %	$ 16,516	50.3 %
Short-term Debt	1,208	3.6	1,650	5.0
Total Debt	18,510	55.2	18,166	55.3
AEP Common Equity	15,007	44.8	14,664	44.7
Noncontrolling Interests	1	-	1	-
Total Debt and Equity Capitalization	$ 33,518	100.0 %	$ 32,831	100.0 %

Our ratio of debt-to-total capital decreased from 55.3% at December 31, 2011 to 55.2% at June 30, 2012. Long-term debt outstanding increased 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. At June 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. At June 30, 2012, our available liquidity was approximately $2.8 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			297	
Total Liquidity Sources			3,547	
Less:	AEP Commercial Paper Outstanding		550	
	Letters of Credit Issued		167	
Net Available Liquidity		$	2,830	

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 six months of 2012 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2012 was 0.46%.

Securitized Accounts Receivables

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. APCo and WPCo anticipate filing, in the third quarter of 2012, a request for a financing order with the WVPSC pursuant to the securitization legislation to securitize approximately $400 million. See "APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing" section of Note 2.

OPCo plans to file, in the third quarter of 2012, an application with the PUCO requesting securitization of the Distribution Asset Recovery Rider (DARR) balance. As of June 30, 2012, OPCo's DARR balance was $309 million, including $145 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018.

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. At June 30, 2012, this contractually-defined percentage was 50%. Nonperformance under these covenants could result in an event of default under these credit agreements. At June 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. At June 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 July 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.

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 221	$ 294
Net Cash Flows from Operating Activities	1,713	1,732
Net Cash Flows Used for Investing Activities	(1,530)	(1,280)
Net Cash Flows Used for Financing Activities	(107)	(329)
Net Increase in Cash and Cash Equivalents	76	123
Cash and Cash Equivalents at End of Period	$ 297	$ 417

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

Operating Activities

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(in millions)	
Net Income	$ 753	$ 708
Depreciation and Amortization	883	813
Other	77	211
Net Cash Flows from Operating Activities	$ 1,713	$ 1,732

Net Cash Flows from Operating Activities were $1.7 billion in 2012 consisting primarily of Net Income of $753 million and $883 million 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 favorable impact of a decrease in accounts receivable and the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Cash was also 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.

Net Cash Flows from Operating Activities were $1.7 billion in 2011 consisting primarily of Net Income of $708 million and $813 million 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. Significant changes in other items include the favorable impact of a decrease in fuel inventory and the unfavorable impact of reducing accounts payable and adjusting accrued taxes for a net operating loss and tax credit carryforward. 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.

Investing Activities

	Six Months Ended June 30, 2012	2011
	(in millions)	
Construction Expenditures	$ (1,371)	$ (1,113)
Acquisitions of Nuclear Fuel	(11)	(93)
Acquisitions of Assets/Businesses	(88)	(10)
Acquisition of Cushion Gas from BOA	-	(214)
Proceeds from Sales of Assets	8	94
Other	(68)	56
Net Cash Flows Used for Investing Activities	$ (1,530)	$ (1,280)

Net Cash Flows Used for Investing Activities were $1.5 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 $1.3 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

	Six Months Ended June 30, 2012	2011
	(in millions)	
Issuance of Common Stock, Net	$ 50	$ 49
Issuance of Debt, Net	332	104
Dividends Paid on Common Stock	(458)	(446)
Other	(31)	(36)
Net Cash Flows Used for Financing Activities	$ (107)	$ (329)

Net Cash Flows Used for Financing Activities in 2012 were $107 million. Our net debt issuances were $332 million. The net issuances included issuances of $800 million of securitization bonds, $275 million of senior unsecured notes and $197 million of notes payable and other debt offset by retirements of $234 million of senior unsecured and other debt notes, $155 million of pollution control bonds, $98 million of securitization bonds and a decrease in short-term borrowing of $442 million. We paid common stock dividends of $458 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 $329 million. Our net debt issuances were $104 million. The net issuances included issuances of $600 million of senior unsecured notes, $481 million of pollution control bonds and an increase in short-term borrowing of $293 million offset by retirements of $578 million of senior unsecured and debt notes, $591 million of pollution control bonds and $92 million of securitization bonds. We paid common stock dividends of $446 million.

In July 2012, I&M retired $9 million of Notes Payable related to DCC Fuel.

In July 2012, TCC retired $73 million of Securitization Bonds.

24

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:

	June 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)
Six Months Ended June 30, 2012

	Utility Operations	Generation and Marketing (in millions)	Total
Total MTM Risk Management Contract Net Assets at December 31, 2011	$59	$132	$191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	14	(14)	-
Fair Value of New Contracts at Inception When Entered During the Period (a)	5	9	14
Changes in Fair Value Due to Market Fluctuations During the Period (b)	5	(1)	4
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	4	-	4
Total MTM Risk Management Contract Net Assets at June 30, 2012	$87	$126	213
Commodity Cash Flow Hedge Contracts			(22)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(35)
Fair Value Hedge Contracts			2
Collateral Deposits			76
Total MTM Derivative Contract Net Assets at June 30, 2012			$234

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 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 June 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 June 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	$ 739	$ 2	$ 737	2	$ 313
Split Rating	-	-	-	-	-
Noninvestment Grade	12	2	10	1	10
No External Ratings:					
Internal Investment Grade	168	-	168	1	42
Internal Noninvestment Grade	58	10	48	1	35
Total as of June 30, 2012	$ 977	$ 14	$ 963	5	$ 400
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 June 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

Six Months Ended June 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 June 30, 2012 and December 31, 2011, the estimated EaR on our debt portfolio for the following twelve months was $37 million and $29 million, respectively.

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

	Three Months Ended 2012	Three Months Ended 2011	Six Months Ended 2012	Six Months Ended 2011
REVENUES				
Utility Operations	$3,235	$3,360	$6,598	$6,857
Other Revenues	316	249	578	482
TOTAL REVENUES	3,551	3,609	7,176	7,339
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	904	980	1,957	2,036
Purchased Electricity for Resale	268	287	528	562
Other Operation	719	697	1,375	1,383
Maintenance	252	316	514	581
Depreciation and Amortization	460	410	883	813
Taxes Other Than Income Taxes	207	202	424	415
TOTAL EXPENSES	2,810	2,892	5,681	5,790
OPERATING INCOME	741	717	1,495	1,549
Other Income (Expense):				
Interest and Investment Income	2	3	4	5
Carrying Costs Income	11	17	31	32
Allowance for Equity Funds Used During Construction	24	23	47	43
Interest Expense	(235)	(239)	(464)	(481)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	543	521	1,113	1,148
Income Tax Expense	190	174	379	452
Equity Earnings of Unconsolidated Subsidiaries	10	6	19	12
NET INCOME	363	353	753	708
Net Income Attributable to Noncontrolling Interests	1	1	2	2
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	362	352	751	706
Preferred Stock Dividend Requirements of Subsidiaries	-	-	-	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$362	$352	$751	$705

WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,500,029	481,928,494	484,164,065	481,538,549
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.75	$0.73	$1.55	$1.46
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	484,860,690	482,203,255	484,554,779	481,786,698
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.75	$0.73	$1.55	$1.46
CASH DIVIDENDS DECLARED PER SHARE	$0.47	$0.46	$0.94	$0.92

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 Six Months Ended June 30, 2012 and 2011
(in millions)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2012	2011	2012	2011
Net Income	$363	$353	$753	$708
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $5 and $2 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $11 and $3 for the Six Months Ended June 30, 2012 and 2011, Respectively	(10)	5	(21)	6
Securities Available for Sale, Net of Tax of $- and $- for the Three Months Ended June 30, 2012 and 2011, Respectively, and $1 and $- for the Six Months Ended June 30, 2012 and 2011, Respectively	(1)	-	1	1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $4 and $3 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $8 and $6 for the Six Months Ended June 30, 2012 and 2011, Respectively	8	6	15	12
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(3)	11	(5)	19
TOTAL COMPREHENSIVE INCOME	360	364	748	727
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	2	2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	359	363	746	725
Preferred Stock Dividend Requirements of Subsidiaries	-	-	-	1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$359	$363	$746	$724

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

31

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

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622
Issuance of Common Stock	1	9	40				49
Common Stock Dividends				(444)		(2)	(446)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			(12)				(12)
Subtotal – Equity							13,212
Net Income				706		2	708
Other Comprehensive Income					19		19
TOTAL EQUITY – JUNE 30, 2011	502	$ 3,266	$ 5,932	$ 5,103	$ (362)	$ -	$ 13,939
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665
Issuance of Common Stock	1	10	40				50
Common Stock Dividends				(456)		(2)	(458)
Other Changes in Equity			3				3
Subtotal – Equity							14,260
Net Income				751		2	753
Other Comprehensive Loss					(5)		(5)
TOTAL EQUITY – JUNE 30, 2012	505	$ 3,284	$ 6,013	$ 6,185	$ (475)	$ 1	$ 15,008

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
June 30, 2012 and December 31, 2011
(in millions)
(Unaudited)

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 297	$ 221
Other Temporary Investments		
(June 30, 2012 and December 31, 2011 Amounts Include $279 and $281, Respectively, Related to Transition Funding and EIS)	297	294
Accounts Receivable:		
Customers	674	690
Accrued Unbilled Revenues	129	106
Pledged Accounts Receivable – AEP Credit	910	920
Miscellaneous	84	150
Allowance for Uncollectible Accounts	(35)	(32)
Total Accounts Receivable	1,762	1,834
Fuel	837	657
Materials and Supplies	657	635
Risk Management Assets	219	193
Accrued Tax Benefits	46	51
Regulatory Asset for Under-Recovered Fuel Costs	126	65
Margin Deposits	63	67
Prepayments and Other Current Assets	179	165
TOTAL CURRENT ASSETS	4,483	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,382	24,938
Transmission	9,372	9,048
Distribution	15,148	14,783
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,862	3,780
Construction Work in Progress	3,020	3,121
Total Property, Plant and Equipment	56,784	55,670
Accumulated Depreciation and Amortization	18,956	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	37,828	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,277	6,026
Securitized Transition Assets	2,241	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,658	1,592
Goodwill	90	76
Long-term Risk Management Assets	439	403
Deferred Charges and Other Noncurrent Assets	1,405	1,346

TOTAL OTHER NONCURRENT ASSETS		11,110		11,070
TOTAL ASSETS	$	53,421	$	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
June 30, 2012 and December 31, 2011
(dollars in millions)
(Unaudited)

	2012	2011
CURRENT LIABILITIES		
Accounts Payable	$ 906	$ 1,095
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	658	666
Other Short-term Debt	550	984
Total Short-term Debt	1,208	1,650
Long-term Debt Due Within One Year		
(June 30, 2012 and December 31, 2011 Amounts Include $368 and $293, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	1,983	1,433
Risk Management Liabilities	165	150
Customer Deposits	293	289
Accrued Taxes	617	717
Accrued Interest	281	279
Regulatory Liability for Over-Recovered Fuel Costs	84	8
Other Current Liabilities	870	990
TOTAL CURRENT LIABILITIES	6,407	6,611
NONCURRENT LIABILITIES		
Long-term Debt		
(June 30, 2012 and December 31, 2011 Amounts Include $2,400 and $1,674, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	15,319	15,083
Long-term Risk Management Liabilities	259	195
Deferred Income Taxes	8,627	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,615	3,195
Asset Retirement Obligations	1,523	1,472
Employee Benefits and Pension Obligations	1,729	1,801
Deferred Credits and Other Noncurrent Liabilities	934	974
TOTAL NONCURRENT LIABILITIES	32,006	30,947
TOTAL LIABILITIES	38,413	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	505,165,281	503,759,460

	2012	2011
	3,284	3,274

(20,336,592 Shares were Held in Treasury at June 30, 2012 and December 31, 2011)				
Paid-in Capital		6,013		5,970
Retained Earnings		6,185		5,890
Accumulated Other Comprehensive Income (Loss)		(475)		(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		15,007		14,664
Noncontrolling Interests		1		1
TOTAL EQUITY		15,008		14,665
TOTAL LIABILITIES AND EQUITY	$	53,421	$	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 Six Months Ended June 30, 2012 and 2011
(in millions)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 753	$ 708
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	883	813
Deferred Income Taxes	417	525
Gain on Settlement with BOA and Enron	-	(51)
Settlement of Litigation with BOA and Enron	-	(211)
Carrying Costs Income	(31)	(32)
Allowance for Equity Funds Used During Construction	(47)	(43)
Mark-to-Market of Risk Management Contracts	8	61
Amortization of Nuclear Fuel	64	72
Property Taxes	68	62
Fuel Over/Under-Recovery, Net	91	(93)
Change in Other Noncurrent Assets	(80)	(11)
Change in Other Noncurrent Liabilities	31	83
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	93	53
Fuel, Materials and Supplies	(199)	146
Accounts Payable	(100)	(87)
Accrued Taxes, Net	(92)	(198)
Other Current Assets	(7)	(9)
Other Current Liabilities	(139)	(56)
Net Cash Flows from Operating Activities	1,713	1,732
INVESTING ACTIVITIES		
Construction Expenditures	(1,371)	(1,113)
Change in Other Temporary Investments, Net	(1)	11
Purchases of Investment Securities	(546)	(645)
Sales of Investment Securities	517	712
Acquisitions of Nuclear Fuel	(11)	(93)
Acquisitions of Assets/Businesses	(88)	(10)
Acquisition of Cushion Gas from BOA	-	(214)
Proceeds from Sales of Assets	8	94
Other Investing Activities	(38)	(22)
Net Cash Flows Used for Investing Activities	(1,530)	(1,280)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	50	49
Issuance of Long-term Debt	1,261	1,074
Commercial Paper and Credit Facility Borrowings	21	357
Change in Short-term Debt, Net	(425)	566

Retirement of Long-term Debt		(487)		(1,263)
Commercial Paper and Credit Facility Repayments		(38)		(630)
Principal Payments for Capital Lease Obligations		(36)		(35)
Dividends Paid on Common Stock		(458)		(446)
Dividends Paid on Cumulative Preferred Stock		-		(1)
Other Financing Activities		5		-
Net Cash Flows Used for Financing Activities		(107)		(329)
Net Increase in Cash and Cash Equivalents		76		123
Cash and Cash Equivalents at Beginning of Period		221		294
Cash and Cash Equivalents at End of Period	$	297	$	417
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	444	$	442
Net Cash Paid (Received) for Income Taxes		(42)		15
Noncash Acquisitions Under Capital Leases		33		28
Construction Expenditures Included in Current Liabilities at June 30,		255		292
Noncash Assumption of Liabilities Related to Acquisitions		56		-

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

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 six months ended June 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 June 30, 2012 and 2011 were $36 million and $30 million, respectively, and for the six months ended June 30, 2012 and 2011 were $91 million and $64 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our condensed balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the three months ended June 30, 2012 and 2011 was $0 and $80 thousand, respectively, and for the six months ended June 30, 2012 and 2011 was $15 million and $30 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 June 30, 2012 and 2011 were $42 million and $38 million, respectively, and for the six months ended June 30, 2012 and 2011 were $59 million and $43 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 $2.4 billion and $1.7 billion at June 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 at June 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
June 30, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding	
ASSETS						
Current Assets	$ 67	$ 147	$ 125	$ 897	$ 235	
Net Property, Plant and Equipment	170	241	-	-	-	
Other Noncurrent Assets	57	143	5	1	2,293	(a)
Total Assets	$ 294	$ 531	$ 130	$ 898	$ 2,528	
LIABILITIES AND EQUITY						
Current Liabilities	$ 42	$ 127	$ 43	$ 851	$ 303	
Noncurrent Liabilities	252	404	67	1	2,207	
Equity	-	-	20	46	18	
Total Liabilities and Equity	$ 294	$ 531	$ 130	$ 898	$ 2,528	

(a) Includes an intercompany item eliminated in consolidation of $92 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 June 30, 2012 and 2011 were $20 million and $15 million, respectively and for the six months ended June 30, 2012 and 2011 were $34 million and $29 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:

	June 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	-	57	-	52
Total Investment in DHLC	$9	$66	$9	$61

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). In February 2011, PJM directed that work on the PATH project be suspended. PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our condensed balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. As of June 30, 2012, PATH-WV had no debt outstanding. However, if debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	June 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		12		12		10		10
Total Investment in PATH-WV	$	31	$	31	$	29	$	29

Earnings Per Share (EPS)

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

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

	Three Months Ended June 30,			
	2012		2011	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 362		$ 352	
Weighted Average Number of Basic Shares Outstanding	484.5	$ 0.75	481.9	$ 0.73
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	484.9	$ 0.75	482.2	$ 0.73

	Six Months Ended June 30,			
	2012		2011	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 751		$ 705	
Weighted Average Number of Basic Shares Outstanding	484.2	$ 1.55	481.5	$ 1.46
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	484.6	$ 1.55	481.8	$ 1.46

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

Options to purchase 10,000 and 70,050 shares of common stock at June 30, 2012 and 2011, respectively, were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive.

2. 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

	June 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	$24	$24
Economic Development Rider	13	13
Regulatory Assets Currently Not Earning a Return		
Virginia Environmental Rate Adjustment Clause	22	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	8	10
Virginia Deferred Wind Power Costs	4	38
Other Regulatory Assets Not Yet Being Recovered	26	14
Total Regulatory Assets Not Yet Being Recovered	$135	$155

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 total up to $698 million, excluding carrying costs.

42

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off of certain pretax earnings 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. If the Supreme Court of Ohio ultimately determines that additional amounts should be refunded, it could reduce future net income and cash flows and impact financial condition.

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 on July 31, 2012 or one month after the PUCO issues an order on the 2010 SEET, whichever is later. 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. See the "2009 – 2011 ESP" section above. 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 deferred into a separate PIRR docket. See the "Proposed June 2012 – May 2015 ESP" section below.

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 Partnership with Ohio and Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in the fourth quarter of 2011.

In March 2012, in response to OPCo's motion for relief, the PUCO ordered that CRES providers not qualifying for the tier one capacity billing rate of $146/MW day, which is substantially below OPCo's current capacity cost of approximately $355/MW day, will pay a tier two capacity billing rate of $255/MW day through May 2012. The PUCO subsequently extended that order until August 8, 2012 or until an order is issued in OPCo's pending June 2012 – May 2015 ESP proceeding, whichever is sooner. See the "Proposed June 2012 – May 2015 ESP" section below.

43

Proposed June 2012 – May 2015 ESP

In March 2012, OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing. The SSO rates would be effective through May 2015. The ESP will transition OPCo to an auction-based SSO for capacity and energy by June 2015. OPCo also 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. Contingent upon OPCo receiving final orders from the PUCO adopting the ESP as proposed and the corporate separation plan as filed, OPCo will conduct an energy-only auction for 5% of the SSO load with delivery beginning six months after the final orders and extending through December 2014. In addition, a competitive bidding process would determine the price of energy for OPCo's SSO load from January 2015 through May 2015. The ESP proposed a two-tiered capacity pricing structure for CRES providers. The first tier is priced at the Reliability Pricing Model (RPM) rate in effect in March 2012 of $146/MW day to serve approximately 21%, 31% and 41% of each customer class through December 2012, December 2013 and for the period January 2014 through May 2015, respectively. All other capacity provided to CRES providers would be offered at $255/MW day. In 2012, an additional amount of capacity may be made available at the $146/MW day rate to accommodate any community aggregation load above 21%, if applicable.

The resolution of the capacity rate is also the subject of separate proceedings before the FERC and the PUCO. In those proceedings, OPCo is seeking a wholesale cost-based capacity rate, currently at approximately $355/MW day. In July 2012, the PUCO issued an order in the capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer 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 pending June 2012 – May 2015 ESP proceeding. The PUCO postponed implementation of the order until August 8, 2012 or until an order is issued in OPCo's pending June 2012 – May 2015 ESP proceeding, whichever is sooner. In July 2012, OPCo requested rehearing of the PUCO order. If OPCo is ultimately not permitted to fully recover its capacity cost deferral, it would reduce future net income and cash flows and impact financial condition.

The ESP also proposed to collect the PIRR from June 2013 through December 2018. As of June 30, 2012, the net PIRR deferral was $538 million, excluding unrecognized equity carrying costs. If OPCo is ultimately not permitted to fully recover its PIRR deferral, it would reduce future net income and cash flows and impact financial condition.

Further, the ESP proposed establishment of a non-bypassable Distribution Investment Rider through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The filing also seeks establishment of a new non-bypassable Retail Stability Rider (RSR) to recover lost generation revenues to provide financial certainty and stability during the ESP transition period. The proposed RSR would be effective through May 2015. Finally, the ESP proposed a storm damage recovery mechanism for the deferral of operation and maintenance costs above $5 million, effective January 2012.

Intervenors and the PUCO staff filed testimony in May 2012 in opposition to many aspects of OPCo's ESP, including the proposed RSR and the two-tiered capacity pricing structure for CRES providers. Intervenors recommended a flash cut to the current RPM rate for capacity. In addition, the PUCO staff's testimony included a proposal to increase the vegetation management base used for calculating over/under recovery on incremental vegetation spend from $21 million to $39 million, which could increase future Other Operation and Maintenance expense by $18 million on an annual basis.

Hearings on the June 2012 – May 2015 ESP were held at the PUCO during the second quarter of 2012 and oral arguments were held in July 2012. A decision from the PUCO is expected in August 2012.

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.

Because the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In March 2012, OPCo filed an application with the PUCO to approve an ESP for the period June 2012 through May 2015, which includes a request for a new DIR. See the "Proposed June 2012 – May 2015 ESP" section above. A decision in the June 2012 – May 2015 ESP proceeding is expected in August 2012. In March 2012, the PUCO issued an order clarifying that OPCo has the right to file a new distribution base rate case. If OPCo is not ultimately permitted to fully recover its costs, it would reduce future net income and cash flows and impact financial condition.

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 June 2012, OPCo filed a notice of appeal with the Supreme Court of Ohio challenging the PUCO's decision to have proceeds from the 2008 coal contract settlement applied to OPCo's under recovered fuel balance. The PUCO filed a motion to dismiss OPCo's notice of appeal at the Supreme Court of Ohio. A decision is pending from the Supreme Court of Ohio.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its results of the 2010 and 2011 FAC audits. The audit reports 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 June 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 $34 million, including $18 million of unrecognized equity carrying costs. 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 June 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 $120 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $120 million for transmission, excluding AFUDC. As of June 30, 2012, excluding costs attributable to its joint owners and a $49 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.6 billion of expenditures, including AFUDC and capitalized interest of $269 million for generation and related transmission costs of $121 million. As of June 30, 2012, the joint owners and SWEPCo have contractual construction obligations of approximately $65 million (including related transmission costs of $3 million). SWEPCo's share of the contractual construction obligations is $48 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. 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 its 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.

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 includes a return on and of the Texas jurisdictional share of Turk Plant generation investment at December 2011 and total estimated transmission costs of the Turk Plant along with associated costs, including operations and maintenance costs. It also proposed vegetation management expenditures and includes recovery of the Stall Unit.

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 (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. If the Supreme Court of Virginia were to issue a favorable decision, it could increase future net income and cash flows.

APCo’s Filings for an IGCC Plant

Through June 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. The proposed rates consist of a Dresden Plant surcharge of $32 million and an increase in the construction surcharge of $2 million, offset by a reduction of $34 million in current ENEC rates. APCo and WPCo anticipate filing, in the third quarter of 2012, a request for a financing order with the WVPSC pursuant to the securitization legislation. Upon completion of the securitization, APCo and WPCo would offset the then current ENEC rates by an amount recovered through the securitization. If the financing order is not issued, APCo and WPCo requested recovery of these costs in current rates. As of June 30, 2012, APCo’s ENEC under-recovery balance of $326 million was recorded in Regulatory Assets on the balance sheet, excluding $6 million of unrecognized equity carrying costs.

In June 2012, a settlement agreement was filed with the WVPSC 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. The settlement agreement did not address an intervenor recommendation that the fuel cost recovery for the Mountaineer Plant be limited to the prudently incurred cost of high sulfur coal which, if approved by the WVPSC, could result in a disallowance of approximately $14 million. Approval of the settlement agreement is pending before the WVPSC. If the WVPSC were to disallow a portion of APCo’s and WPCo’s deferred ENEC costs, it could reduce APCo’s future net income and cash flows and impact financial condition.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a 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%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate fuel transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of those ERCOT trading contracts. Hearings were held in June 2011. In June 2012, an Administrative Law Judge issued a report that affirmed the margin sharing amount of 25% and found that the OCC does not have the jurisdiction to grant the relief sought by the OIEC regarding the comprehensive review of all affiliate fuel transactions and the ERCOT trading contracts. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

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 a $25 million increase in annual depreciation expense.

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.

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 Public Convenience and Necessity and authorize I&M to defer, on an interim basis, incremental depreciation and property tax costs, including interest, along with study, analysis and development costs until the applicable costs are included in I&M's base rates. As of June 30, 2012, I&M has incurred $92 million related to the LCM Project. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

KPCo Rate Matters

Big Sandy Unit 2 FGD System

In May 2012, KPCo filed a motion with the KPSC to withdraw its application seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system. The motion was accepted by the KPSC in May 2012. KPCo is currently re-evaluating its needs to meet the short and long-term energy needs of its customers at the most reasonable costs. KPCo has not determined its future plan. As of June 30, 2012, KPCo has incurred $29 million related to the project. Management intends to pursue recovery of all costs related to this 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. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the 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. It is unknown at this time 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. Management intends to file an application to terminate the Interconnection Agreement with the FERC in the future. 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 June 30, 2012, the maximum future payments for letters of credit issued under the credit facilities were $167 million with maturities ranging from July 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 June 30, 2012, SWEPCo has collected approximately $56 million through a rider for final mine closure and reclamation costs, of which $11 million is recorded in Other Current Liabilities, $3 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $42 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 June 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 June 30, 2012, the maximum potential loss for these lease agreements was approximately $17 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 June 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

51

$95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. The court heard oral argument in November 2011. 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 June 30, 2012, we recorded $64 million in Prepayments and Other Current Assets on our condensed balance sheets representing amounts under NEIL insurance policies. Through June 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.

52

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. 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

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.

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 six months ended June 30, 2012 and 2011:

	Pension Plans Three Months Ended June 30,		Other Postretirement Benefit Plans Three Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Service Cost	$19	$18	$11	$10
Interest Cost	55	60	26	27
Expected Return on Plan Assets	(79)	(78)	(25)	(27)
Amortization of Prior Service Credit	-	-	(4)	-
Amortization of Net Actuarial Loss	38	31	15	8
Net Periodic Benefit Cost	$33	$31	$23	$18

	Pension Plans Six Months Ended June 30,		Other Postretirement Benefit Plans Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Service Cost	$38	$36	$23	$21
Interest Cost	111	119	52	54
Expected Return on Plan Assets	(159)	(157)	(50)	(54)
Amortization of Prior Service Credit	-	-	(9)	-
Amortization of Net Actuarial Loss	75	61	29	15
Net Periodic Benefit Cost	$65	$59	$45	$36

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 that were established in 2009 and our 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 six months ended June 30, 2012 and 2011 and balance sheet information as of June 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.

		Nonutility Operations					
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended June 30, 2012							
Revenues from:							
External Customers	$ 3,234	$ 1	$ 163	$ 148	$ 5	$ -	$ 3,551
Other Operating Segments	24	1	4	-	1	(30)	-
Total Revenues	$ 3,258	$ 2	$ 167	$ 148	$ 6	$ (30)	$ 3,551
Net Income (Loss)	$ 365	$ 8	$ 3	$ (5)	$ (8)	$ -	$ 363

		Nonutility Operations					
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended June 30, 2011							
Revenues from:							
External Customers	$ 3,359	$ 1	$ 162	$ 79	$ 8	$ -	$ 3,609
Other Operating Segments	29	(1)	4	-	2	(34)	-
Total Revenues	$ 3,388	$ -	$ 166	$ 79	$ 10	$ (34)	$ 3,609
Net Income (Loss)	$ 350	$ 6	$ (1)	$ 11	$ (13)	$ -	$ 353

		Nonutility Operations					
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Six Months Ended June 30, 2012							
Revenues from:							
External Customers	$ 6,596	$ 2	$ 335	$ 233	$ 10	$ -	$ 7,176
Other Operating Segments	47	3	11	-	3	(64)	-
Total Revenues	$ 6,643	$ 5	$ 346	$ 233	$ 13	$ (64)	$ 7,176

Net Income (Loss)	$	749	$	17	$	12	$	(6)	$	(19)	$	-	$	753

	Nonutility Operations													
	Utility Operations		Transmission Operations		AEP River Operations		Generation and Marketing		All Other (a)		Reconciling Adjustments		Consolidated	
	(in millions)													
Six Months Ended June 30, 2011														
Revenues from:														
External Customers	$	6,856	$	1	$	329	$	141	$	12	$	-	$	7,339
Other Operating Segments		56		(1)		9		1		3		(68)		-
Total Revenues	$	6,912	$	-	$	338	$	142	$	15	$	(68)	$	7,339
Net Income (Loss)	$	724	$	10	$	6	$	12	$	(44)	$	-	$	708

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
June 30, 2012							
Total Property, Plant and Equipment	$ 55,289	$ 508	$ 624	$ 618	$ 11	$ (266)	$ 56,784
Accumulated Depreciation and Amortization	18,627	2	150	232	10	(65)	18,956
Total Property, Plant and Equipment - Net	$ 36,662	$ 506	$ 474	$ 386	$ 1	$ (201)	$ 37,828
Total Assets	$ 50,983	$ 865	$ 650	$ 1,030	$ 16,638	$ (16,745) (c)	$ 53,421

	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.

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

Trading Strategies

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

Risk Management Strategies

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

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

The following table represents the gross notional volume of our outstanding derivative contracts as of June 30, 2012 and December 31, 2011:

Notional Volume of Derivative Instruments

	Volume		
	June 30, 2012	December 31, 2011	Unit of Measure
Primary Risk Exposure	(in millions)		
Commodity:			
Power	704	609	MWHs
Coal	16	21	Tons
Natural Gas	115	100	MMBtus
Heating Oil and Gasoline	4	6	Gallons
Interest Rate	$ 296	$ 226	USD
Interest Rate and Foreign Currency	$ 803	$ 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 June 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 $94 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 June 30, 2012 and December 31, 2011:

Fair Value of Derivative Instruments
June 30, 2012

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in millions)		
Current Risk Management Assets	$ 996	$ 37	$ 1	$ (815)	$ 219
Long-term Risk Management Assets	733	15	1	(310)	439
Total Assets	1,729	52	2	(1,125)	658
Current Risk Management Liabilities	951	53	33	(872)	165
Long-term Risk Management Liabilities	586	21	2	(350)	259
Total Liabilities	1,537	74	35	(1,222)	424
Total MTM Derivative Contract Net Assets (Liabilities)	$ 192	$ (22)	$ (33)	$ 97	$ 234

Fair Value of Derivative Instruments
December 31, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in millions)		
Current Risk Management Assets	$ 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
Long-term Risk Management Liabilities	483	15	22	(325)	195
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 six months ended June 30, 2012 and 2011:

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

Location of Gain (Loss)		2012		2011
		(in millions)		
Utility Operations Revenues	$	4	$	18
Other Revenues		5		13
Regulatory Assets (a)		(17)		(5)
Regulatory Liabilities (a)		13		5
Total Gain (Loss) on Risk Management Contracts	$	5	$	31

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

Location of Gain (Loss)		2012		2011
		(in millions)		
Utility Operations Revenues	$	14	$	38
Other Revenues		8		15
Regulatory Assets (a)		(38)		(1)
Regulatory Liabilities (a)		27		11
Total Gain (Loss) on Risk Management Contracts	$	11	$	63

(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.”

61

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 six months ended June 30, 2012, we recognized gains of $1 million and $2 million, respectively, on our hedging instruments and offsetting losses of $1 million and $2 million, respectively, on our long-term debt. During the three and six months ended June 30, 2011, we recognized gains of $4 million and $8 million, respectively, on our hedging instruments and offsetting losses of $5 million and $9 million, respectively, on our long-term debt. During the three and six months ended June 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 six months ended June 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 six months ended June 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 six months ended June 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 six months ended June 30, 2012 and 2011, we designated foreign currency derivatives as cash flow hedges.

During the three and six months ended June 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 six months ended June 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 June 30, 2012

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of March 31, 2012	$ (16)	$ (18)	$ (34)
Changes in Fair Value Recognized in AOCI	(3)	(13)	(16)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(2)	-	(2)
Purchased Electricity for Resale	6	-	6
Interest Expense	-	1	1
Regulatory Assets (a)	1	-	1
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of June 30, 2012	$ (14)	$ (30)	$ (44)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2011

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of March 31, 2011	$ 8	$ 4	$ 12
Changes in Fair Value Recognized in AOCI	3	-	3
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	2	-	2
Other Revenues	(1)	-	(1)
Purchased Electricity for Resale	(1)	-	(1)
Interest Expense	-	1	1
Regulatory Assets (a)	1	-	1
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of June 30, 2011	$ 12	$ 5	$ 17

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 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	(23)	(12)	(35)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(3)	-	(3)
Purchased Electricity for Resale	13	-	13
Interest Expense	-	2	2
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of June 30, 2012	$ (14)	$ (30)	$ (44)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 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	5	(1)	4
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	2	-	2
Other Revenues	(2)	-	(2)
Purchased Electricity for Resale	(1)	-	(1)
Interest Expense	-	2	2
Regulatory Assets (a)	1	-	1
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of June 30, 2011	$ 12	$ 5	$ 17

(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 June 30, 2012 and December 31, 2011 were:

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

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 38	$ -	$ 38
Hedging Liabilities (a)	60	35	95
AOCI Gain (Loss) Net of Tax	(14)	(30)	(44)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(10)	(3)	(13)

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

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
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 June 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 39 months.

Credit Risk

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

We use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under 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 June 30, 2012 and December 31, 2011:

	June 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	35	39
Amount Attributable to RTO and ISO Activities	33	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 June 30, 2012 and December 31, 2011:

	June 30, 2012	December 31, 2011
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to ContractualNetting Arrangements	$658	$515
Amount of Cash Collateral Posted	10	56
Additional Settlement Liability if Cross Default Provision is Triggered	375	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.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. To a lesser extent, these contracts could be sensitive to volumetric estimates for some structured transactions. However, a significant portion of our Level 3 volumetric contractual positions 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 June 30, 2012 and December 31, 2011 are summarized in the following table:

	June 30, 2012		December 31, 2011	
	Book Value	Fair Value	Book Value	Fair Value

		(in millions)		
Long-term Debt	$ 17,302	$ 20,025	$ 16,516	$ 19,259

67

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:

	June 30, 2012			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 217	$ -	$ -	$ 217
Fixed Income Securities:				
Mutual Funds	64	1	-	65
Equity Securities - Mutual Funds	11	4	-	15
Total Other Temporary Investments	$ 292	$ 5	$ -	$ 297

	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 six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Proceeds from Investment Sales	$ -	$ 51	$ -	$ 247
Purchases of Investments	1	5	1	153
Gross Realized Gains on Investment Sales	-	-	-	-
Gross Realized Losses on Investment Sales	-	-	-	-

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

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 six months ended June 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 June 30, 2012

	(in millions)
Balance in AOCI as of March 31, 2012	$ 4
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 June 30, 2012	$ 3

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

	(in millions)
Balance in AOCI as of December 31, 2011	$ 2
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 June 30, 2012	$ 3

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 June 30, 2012 and December 31, 2011:

	June 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	$ 16	$ -	$ -	$ 18	$ -	$ -
Fixed Income Securities:						
United States Government	644	104	(1)	544	61	(1)
Corporate Debt	44	5	(1)	54	5	(2)
State and Local Government	256	1	(1)	330	-	(2)
Subtotal Fixed Income Securities	944	110	(3)	928	66	(5)
Equity Securities - Domestic	698	258	(79)	646	215	(80)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,658	$ 368	$ (82)	$ 1,592	$ 281	$ (85)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Proceeds from Investment Sales	$ 183	$ 177	$ 517	$ 465
Purchases of Investments	192	186	545	492
Gross Realized Gains on Investment Sales	3	7	5	12
Gross Realized Losses on Investment Sales	1	4	2	9

The adjusted cost of debt securities was $834 million and $862 million as of June 30, 2012 and December 31, 2011, respectively. The adjusted cost of equity securities was $440 million and $431 million as of June 30, 2012 and December 31, 2011, respectively.

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

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 40
1 year – 5 years	362
5 years – 10 years	315
After 10 years	227
Total	$ 944

70

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 June 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
June 30, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$20	$-	$-	$277	$297
Other Temporary Investments					
Restricted Cash (a)	186	-	-	31	217
Fixed Income Securities:					
Mutual Funds	65	-	-	-	65
Equity Securities - Mutual Funds (b)	15	-	-	-	15
Total Other Temporary Investments	266	-	-	31	297
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	53	1,509	163	(1,128)	597
Cash Flow Hedges:					
Commodity Hedges (c)	13	38	1	(14)	38
Fair Value Hedges	-	2	-	-	2
De-designated Risk Management Contracts (d)	-	-	-	21	21
Total Risk Management Assets	66	1,549	164	(1,121)	658
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	4	-	12	16
Fixed Income Securities:					
United States Government	-	644	-	-	644
Corporate Debt	-	44	-	-	44
State and Local Government	-	256	-	-	256
Subtotal Fixed Income Securities	-	944	-	-	944
Equity Securities - Domestic (b)	698	-	-	-	698
Total Spent Nuclear Fuel and Decommissioning Trusts	698	948	-	12	1,658
Total Assets	$1,050	$2,497	$164	$(801)	$2,910

Liabilities:

Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$47	$1,419	$67	$(1,204)	$329
Cash Flow Hedges:					
Commodity Hedges (c)	-	74	-	(14)	60
Interest Rate/Foreign Currency Hedges	-	35	-	-	35
Total Risk Management Liabilities	$47	$1,528	$67	$(1,218)	$424

71

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 June 30, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $2 million in 2012, $12 million in periods 2013-2015 and ($8) million in periods 2016-2018; Level 2 matures $12 million in 2012, $52 million in periods 2013-2015, $17 million in periods 2016-2017 and $9 million in periods 2018-2030; Level 3 matures $7 million in 2012, $38 million in periods 2013-2015, $24 million in periods 2016-2017 and $27 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 six months ended June 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 June 30, 2012		Net Risk Management Assets (Liabilities) (in millions)	
Balance as of March 31, 2012	$	92	
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)		4	
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-	
Purchases, Issuances and Settlements (c)		15	
Transfers into Level 3 (d) (f)		(1	)
Transfers out of Level 3 (e) (f)		(8	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		6	
Balance as of June 30, 2012	$	97	

Three Months Ended June 30, 2011		Net Risk Management Assets (Liabilities) (in millions)	
Balance as of March 31, 2011	$	73	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(10	)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)			
Relating to Assets Still Held at the Reporting Date (a)		10	
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-	
Purchases, Issuances and Settlements (c)		14	
Transfers into Level 3 (d) (f)		3	
Transfers out of Level 3 (e) (f)		(4	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		(9	)
Balance as of June 30, 2011	$	77	

Six Months Ended June 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)	(17)
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)	33
Transfers into Level 3 (d) (f)	14
Transfers out of Level 3 (e) (f)	(20)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	13
Balance as of June 30, 2012	$ 97

Six Months Ended June 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)	(9)
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	-
Purchases, Issuances and Settlements (c)	6
Transfers into Level 3 (d) (f)	4
Transfers out of Level 3 (e) (f)	(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(4)
Balance as of June 30, 2011	$ 77

(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 June 30, 2012:

	Fair Value		Valuation	Significant Unobservable	Forward Price Range	
	Assets	Liabilities	Technique	Input (a)	Low	High
	(in millions)					
Energy Contracts	$ 152	$ 60	Discounted Cash Flow	Forward Market Price	$ 10.76	$ 174.18
FTRs	12	7	Discounted Cash Flow	Forward Market Price	(10.77)	10.78
Total	$ 164	$ 67				

(a) Represents market prices beyond defined terms for Levels 1 and 2.

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.

10. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	June 30, 2012	December 31, 2011
	(in millions)	
Senior Unsecured Notes	$ 11,858	$ 11,737
Pollution Control Bonds	1,958	2,112
Notes Payable	497	402
Securitization Bonds	2,389	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	(37)	(39)
Total Long-term Debt Outstanding	17,302	16,516
Long-term Debt Due Within One Year	1,983	1,433
Long-term Debt	$ 15,319	$ 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 at both June 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 six months of 2012 are shown in the tables below:

Company	Type of Debt		Principal Amount (in millions)		Interest Rate (%)	Due Date
Issuances:						
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		$	1,272	(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 $1,261 million is net of issuance costs and premium or discount.

Company	Type of Debt		Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
APCo	Pollution Control Bonds	$	30	6.05	2024
APCo	Pollution Control Bonds		20	5.00	2021
I&M	Notes Payable		14	5.44	2013
I&M	Notes Payable		11	4.00	2014
I&M	Notes Payable		11	Variable	2015
I&M	Notes Payable		12	Variable	2016
I&M	Notes Payable		8	2.12	2016
OPCo	Pollution Control Bonds		45	4.85	2012
OPCo	Senior Unsecured Notes		150	Variable	2012
SWEPCo	Notes Payable		20	7.03	2012
Non-Registrant:					
AEP Subsidiaries	Notes Payable		4	Variable	2017
AEP Subsidiaries	Notes Payable		1	7.59-8.03	2026
AEGCo	Senior Unsecured Notes		3	6.33	2037
TCC	Securitization Bonds		63	4.98	2013
TCC	Securitization Bonds		35	5.96	2013
TCC	Pollution Control Bonds		60	1.125	2012
Total Retirements and Principal Payments		$	487		

In July 2012, I&M retired $9 million of Notes Payable related to DCC Fuel.

In July 2012, TCC retired $73 million of Securitization Bonds.

As of June 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 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:

	June 30, 2012		December 31, 2011	
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
Securitized Debt for Receivables (b)	$ 658	0.27 %	$ 666	0.27 %
Commercial Paper	550	0.46 %	967	0.51 %
Line of Credit – Sabine (c)	-	- %	17	1.79 %
Total Short-term Debt	$ 1,208		$ 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.26 %	0.26 %	0.26 %	0.28 %
Net Uncollectible Accounts Receivable Written Off	$ 6	$ 6	$ 14	$ 17

	June 30, 2012	December 31, 2011
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral		
Less Uncollectible Accounts	$ 888	$ 902
Total Principal Outstanding	658	666
Delinquent Securitized Accounts Receivable	35	38
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	21	18
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	355	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 by the end of 2012. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge to expense in the second quarter of 2012 related to the sustainable cost reductions initiative.

	Total (in millions)
Incurred	$ 13

Settled		(5)
Remaining Balance at June 30, 2012	$	8

These expenses relate primarily to severance benefits. They are included primarily in Other Operation on the income statement and Other Current Liabilities on the balance sheet. 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 earnings, 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

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. It is unknown at this time 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. Management intends to file an application to terminate the Interconnection Agreement with the FERC in the future. 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.

Virginia Regulatory Activity

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.

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. APCo and WPCo anticipate filing, in the third quarter of 2012, a request for a financing order with the WVPSC pursuant to the securitization legislation to securitize approximately $400 million. See "APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing" section of Note 2.

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 future. See "WPCo Merger with APCo" section of Note 2.

Storm Damage

In late June 2012 and early July 2012, APCo was significantly impacted by several severe storms. In the second quarter of 2012, APCo recorded minimal incremental operation and maintenance expenses related to the June 2012 storms. APCo expects to incur an estimated $95 million in total storm restoration costs in the third quarter of 2012, including an estimated $25 million in capital spending related to these storms and an estimated $70 million in incremental operation and maintenance costs. APCo intends to defer the majority of the incremental operation and maintenance costs and seek future recovery. If APCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

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 146. 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 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions of KWHs)			
Retail:				
Residential	2,184	2,367	5,634	6,326
Commercial	1,683	1,696	3,309	3,394
Industrial	2,702	2,699	5,306	5,318
Miscellaneous	201	204	402	414
Total Retail (a)	6,770	6,966	14,651	15,452
Wholesale	1,492	2,336	2,873	4,163
Total KWHs	8,262	9,302	17,524	19,615

(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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	61	56	983	1,387
Normal - Heating (b)	97	100	1,440	1,437

Actual - Cooling (c)	419	464	444	470
Normal - Cooling (b)	354	348	360	354

(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.

Second Quarter of 2012 Compared to Second Quarter of 2011

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

Second Quarter of 2011	$	32
Changes in Gross Margin:		
Retail Margins		52
Off-system Sales		(2)
Transmission Revenues		2
Other Revenues		(2)
Total Change in Gross Margin		50
Changes in Expenses and Other:		
Other Operation and Maintenance		21
Depreciation and Amortization		(17)
Taxes Other Than Income Taxes		1
Carrying Costs Income		(1)
Other Income		(2)
Interest Expense		1
Total Change in Expenses and Other		3
Income Tax Expense		(23)
Second Quarter of 2012	$	62

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 $52 million primarily due to the following:
  - A $––28 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 the third quarter of 2011.
  - A $9 million increase due to higher rates in Virginia.
  - A $9 million increase of additional wind purchase recovery costs deferred as a result of the June 2012 Virginia SCC fuel factor order.
  - A $6 million increase in recoverable PJM expenses.

  These increases were partially offset by:
  - A $7 million decrease in residential and commercial margins primarily due to lower non-weather related usage.
  - A $3 million decrease in weather-related usage primarily due to a 9% decrease in cooling degree days.
- Margins from Off-system Sales decreased $2 million primarily due to lower 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 $21 million primarily due to the following:
  - A $10 million decrease in distribution expenses resulting from storm damage repairs in 2011.
  - A $7 million decrease due to the deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause.
  - A $6 million decrease due to lower boiler maintenance expenses in 2012 at all six APCo coal-fueled power plants.

  These decreases were partially offset by:
  - A $3 million increase due to expenses related to the 2012 sustainable cost reductions.
- Depreciation and Amortization expenses increased $17 million primarily due to:
  - A $10 million increase in depreciation as a result of increased depreciation rates in Virginia effective February 2012.
  - A $5 million increase in amortization primarily as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012.
- Income Tax Expense increased $23 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Reconciliation of Six Months Ended June 30, 2011 to Six Months Ended June 30, 2012
Net Income
(in millions)

Six Months Ended June 30, 2011	$	71
Changes in Gross Margin:		
Retail Margins		95
Off-system Sales		(6)
Transmission Revenues		5
Other Revenues		(4)
Total Change in Gross Margin		90
Changes in Expenses and Other:		
Other Operation and Maintenance		46
Depreciation and Amortization		(29)
Taxes Other Than Income Taxes		1
Carrying Costs Income		3
Other Income		(2)
Interest Expense		3
Total Change in Expenses and Other		22
Income Tax Expense		(45)
Six Months Ended June 30, 2012	$	138

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 $95 million primarily due to the following:
  · A $55 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 the third quarter of 2011.
  · A $31 million increase due to higher base rates in Virginia and West Virginia.
  · An $18 million increase in other variable electric generation expenses.
  · A $13 million increase in recoverable PJM expenses.
  · A $9 million increase of additional wind purchase recovery costs deferred as a result of the June 2012 Virginia SCC fuel factor order.

  These increases were partially offset by:
  · A $33 million decrease in weather-related usage primarily due to a 31% decrease in heating degree days.
  · An $8 million decrease in residential and commercial margins primarily due to lower non-weather related usage.

· Margins from Off-system Sales decreased $6 million primarily due to lower physical sales volumes and lower trading and marketing margins.

· Transmission Revenues increased $5 million primarily due to increased Network Transmission Service revenue requirements beginning in July 2011.
· Other Revenues decreased $4 million primarily due to gains on sales of SO2 allowances in the first quarter of 2011.

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

- Other Operation and Maintenance expenses decreased $46 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 $14 million decrease due to the deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause.
  - An $11 million decrease due to 2011 storm expenses.
  - A $7 million decrease due to lower boiler maintenance expenses in 2012 at all six APCo coal-fueled power plants.

  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.
  - A $3 million increase due to expenses related to the 2012 sustainable cost reductions.
- Depreciation and Amortization expenses increased $29 million primarily due to:
  - A $17 million increase in depreciation as a result of increased depreciation rates in Virginia effective February 2012.
  - A $9 million increase in amortization primarily as a result of the Virginia E&R surcharge and the Virginia Environmental Rate Adjustment Clause, both effective February 2012.
- Carrying Costs Income increased $3 million primarily due to carrying charges on the Dresden Plant resulting from the Virginia Generation Rate Adjustment Clause and the West Virginia Expanded Net Energy Charge.
- Interest Expense decreased $3 million primarily due to lower interest rates on long-term debt.
- Income Tax Expense increased $45 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 201 for a discussion of accounting pronouncements.

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

	Three Months Ended 2012	Three Months Ended 2011	Six Months Ended 2012	Six Months Ended 2011
REVENUES				
Electric Generation, Transmission and Distribution	$647,236	$666,785	$1,385,835	$1,417,797
Sales to AEP Affiliates	67,043	82,531	131,344	161,222
Other Revenues	2,182	2,129	4,758	4,246
TOTAL REVENUES	716,461	751,445	1,521,937	1,583,265
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	181,653	184,698	368,537	365,279
Purchased Electricity for Resale	44,869	69,127	110,225	138,345
Purchased Electricity from AEP Affiliates	125,864	183,661	281,881	407,850
Other Operation	72,685	74,617	147,004	187,893
Maintenance	37,830	57,163	84,165	89,456
Depreciation and Amortization	85,139	67,644	165,552	136,743
Taxes Other Than Income Taxes	24,995	25,968	51,957	53,071
TOTAL EXPENSES	573,035	662,878	1,209,321	1,378,637
OPERATING INCOME	143,426	88,567	312,616	204,628
Other Income (Expense):				
Interest Income	359	762	702	1,082
Carrying Costs Income	5,467	6,542	13,252	9,981
Allowance for Equity Funds Used During Construction	4	1,212	517	2,095
Interest Expense	(51,945)	(53,188)	(103,252)	(106,127)
INCOME BEFORE INCOME TAX EXPENSE	97,311	43,895	223,835	111,659
Income Tax Expense	34,979	12,268	86,192	41,052
NET INCOME	62,332	31,627	137,643	70,607
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	200	-	400
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$62,332	$31,427	$137,643	$70,207

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	Three Months Ended		Six Months Ended	
	2012	2011	2012	2011
Net Income	$ 62,332	$ 31,627	$ 137,643	$ 70,607
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $305 and $377 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $15 and $652 for the Six Months Ended June 30, 2012 and 2011, Respectively	566	700	27	1,211
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $484 and $419 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $969 and $837 for the Six Months Ended June 30, 2012 and 2011, Respectively	899	777	1,799	1,554
TOTAL OTHER COMPREHENSIVE INCOME	1,465	1,477	1,826	2,765
TOTAL COMPREHENSIVE INCOME	$ 63,797	$ 33,104	$ 139,469	$ 73,372

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 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
Common Stock Dividends			(67,500)		(67,500)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense		3			3
Subtotal – Common Shareholder's Equity					2,753,782
Net Income			70,607		70,607
Other Comprehensive Income				2,765	2,765
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2011	$ 260,458	$ 1,475,499	$ 1,136,455	$ (45,258)	$ 2,827,154
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 260,458	$ 1,573,752	$ 1,160,747	$ (58,543)	$ 2,936,414
Common Stock Dividends			(100,000)		(100,000)
Subtotal – Common Shareholder's Equity					2,836,414
Net Income			137,643		137,643
Other Comprehensive Income				1,826	1,826
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2012	$ 260,458	$ 1,573,752	$ 1,198,390	$ (56,717)	$ 2,975,883

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

		2012		2011
CURRENT ASSETS				
Cash and Cash Equivalents	$	2,109	$	2,317
Advances to Affiliates		22,573		22,008
Accounts Receivable:				
Customers		145,133		158,382
Affiliated Companies		70,561		136,194
Accrued Unbilled Revenues		47,419		68,427
Miscellaneous		456		5,505
Allowance for Uncollectible Accounts		(4,413)		(5,289)
Total Accounts Receivable		259,156		363,219
Fuel		197,342		143,931
Materials and Supplies		103,267		101,724
Risk Management Assets		41,841		39,645
Accrued Tax Benefits		320		7,715
Regulatory Asset for Under-Recovered Fuel Costs		102,091		41,105
Prepayments and Other Current Assets		18,857		21,745
TOTAL CURRENT ASSETS		747,556		743,409
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Generation		5,563,066		5,194,967
Transmission		2,007,141		1,943,969
Distribution		2,901,775		2,845,405
Other Property, Plant and Equipment		373,255		357,326
Construction Work in Progress		217,902		565,841
Total Property, Plant and Equipment		11,063,139		10,907,508
Accumulated Depreciation and Amortization		3,087,299		2,994,016
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET		7,975,840		7,913,492
OTHER NONCURRENT ASSETS				
Regulatory Assets		1,404,116		1,481,193
Long-term Risk Management Assets		44,676		39,226
Deferred Charges and Other Noncurrent Assets		110,514		122,187
TOTAL OTHER NONCURRENT ASSETS		1,559,306		1,642,606
TOTAL ASSETS	$	10,282,702	$	10,299,507

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

		2012		2011
		(in thousands)		
CURRENT LIABILITIES				
Advances from Affiliates	$	166,988	$	198,248
Accounts Payable:				
General		139,851		186,612
Affiliated Companies		107,129		137,376
Long-term Debt Due Within One Year – Nonaffiliated		545,027		594,525
Risk Management Liabilities		23,036		26,606
Customer Deposits		60,971		61,690
Deferred Income Taxes		38,857		14,255
Accrued Taxes		85,479		63,422
Accrued Interest		56,561		57,230
Other Current Liabilities		88,886		105,646
TOTAL CURRENT LIABILITIES		1,312,785		1,445,610
NONCURRENT LIABILITIES				
Long-term Debt – Nonaffiliated		3,132,089		3,131,726
Long-term Risk Management Liabilities		22,638		12,923
Deferred Income Taxes		1,766,932		1,736,180
Regulatory Liabilities and Deferred Investment Tax Credits		620,058		576,792
Employee Benefits and Pension Obligations		296,168		302,182
Deferred Credits and Other Noncurrent Liabilities		156,149		157,680
TOTAL NONCURRENT LIABILITIES		5,994,034		5,917,483
TOTAL LIABILITIES		7,306,819		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		1,198,390		1,160,747
Accumulated Other Comprehensive Income (Loss)		(56,717)		(58,543)
TOTAL COMMON SHAREHOLDER’S EQUITY		2,975,883		2,936,414
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$	10,282,702	$	10,299,507

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 137,643	$ 70,607
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	165,552	136,743
Deferred Income Taxes	56,927	127,525
Carrying Costs Income	(13,252)	(9,981)
Allowance for Equity Funds Used During Construction	(517)	(2,095)
Mark-to-Market of Risk Management Contracts	(2,323)	7,343
Fuel Over/Under-Recovery, Net	26,417	(21,132)
Change in Other Noncurrent Assets	(16,708)	11,361
Change in Other Noncurrent Liabilities	18,266	5,239
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	103,680	84,748
Fuel, Materials and Supplies	(54,954)	85,449
Accounts Payable	(43,538)	(62,795)
Accrued Taxes, Net	30,032	(56,411)
Other Current Assets	2,579	6,281
Other Current Liabilities	(15,880)	3,316
Net Cash Flows from Operating Activities	393,924	386,198
INVESTING ACTIVITIES		
Construction Expenditures	(212,959)	(191,125)
Change in Advances to Affiliates, Net	(565)	(162,787)
Other Investing Activities	3,158	7,832
Net Cash Flows Used for Investing Activities	(210,366)	(346,080)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	640,164
Change in Advances from Affiliates, Net	(31,260)	(128,331)
Retirement of Long-term Debt – Nonaffiliated	(49,512)	(479,661)
Retirement of Cumulative Preferred Stock	-	(8)
Principal Payments for Capital Lease Obligations	(3,258)	(3,720)
Dividends Paid on Common Stock	(100,000)	(67,500)
Dividends Paid on Cumulative Preferred Stock	-	(400)
Other Financing Activities	264	19
Net Cash Flows Used for Financing Activities	(183,766)	(39,437)
Net Increase (Decrease) in Cash and Cash Equivalents	(208)	681
Cash and Cash Equivalents at Beginning of Period	2,317	951
Cash and Cash Equivalents at End of Period	$ 2,109	$ 1,632

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 100,319	$ 100,127
Net Cash Paid (Received) for Income Taxes	(10,090)	(33,371)
Noncash Acquisitions Under Capital Leases	1,265	565
Government Grants Included in Accounts Receivable at June 30,	-	4,061
Construction Expenditures Included in Current Liabilities at June 30,	30,439	52,421

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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 146.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

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. It is unknown at this time 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. Management intends to file an application to terminate the Interconnection Agreement with the FERC in the future. 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.

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 a $25 million increase in annual depreciation expense.

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.

Storm Damage

In late June 2012 and early July 2012, I&M was significantly impacted by several severe storms. In the second quarter of 2012, I&M recorded minimal incremental operation and maintenance expenses related to the June 2012 storms. I&M expects to incur an estimated $20 million in total storm restoration costs in the third quarter of 2012, including an estimated $5 million in capital spending related to these storms and an estimated $15 million in incremental operation and maintenance costs. Management is currently evaluating whether I&M will pursue recovery for the incremental operation and maintenance costs in the future.

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 set 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. I&M filed its cost of service proposal in June 2012. 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. I&M is currently receiving compensation through PJM from billings to AES at the Reliability Pricing Model rate, which is less than I&M’s cost of service by approximately $8 million annually.

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. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. 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 tightening oversight of nuclear generating facilities. Management is unable to predict the impact of potential future regulation of nuclear facilities.

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 Public Convenience and Necessity and authorize I&M to defer, on an interim basis, incremental depreciation and property tax costs, including interest, along with study, analysis and development costs until the applicable costs are included in I&M's base rates. As of June 30, 2012, I&M has incurred $92 million related to the LCM Project. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

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 146. 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 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions of KWHs)			
Retail:				
Residential	1,217	1,170	2,786	3,006
Commercial	1,290	1,188	2,456	2,452
Industrial	1,964	1,871	3,797	3,715
Miscellaneous	15	15	38	38
Total Retail (a)	4,486	4,244	9,077	9,211
Wholesale	2,068	2,408	4,029	4,504
Total KWHs	6,554	6,652	13,106	13,715

(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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	163	228	1,784	2,620
Normal - Heating (b)	235	238	2,420	2,414
Actual - Cooling (c)	369	304	398	304
Normal - Cooling (b)	256	252	257	253

(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.

Second Quarter of 2012 Compared to Second Quarter of 2011

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

Second Quarter of 2011	$	31
Changes in Gross Margin:		
Retail Margins		10
FERC Municipals and Cooperatives		(1)
Off-system Sales		(4)
Transmission Revenues		1
Other Revenues		(2)
Total Change in Gross Margin		4
Changes in Expenses and Other:		
Other Operation and Maintenance		(1)
Depreciation and Amortization		(4)
Taxes Other Than Income Taxes		2
Other Income		(1)
Interest Expense		(1)
Total Change in Expenses and Other		(5)
Second Quarter of 2012	$	30

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 $10 million primarily due to the following:
  - A $10 million increase due to industrial and commercial usage.
  - A $6 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 $4 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.
  - A $3 million increase due to a decrease in the AEGCo power bill.

  These increases were partially offset by:
  - A $16 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 $1 million primarily due to the following:
  - An $11 million decrease due to an annual base rate adjustment to actual costs.

  This decrease was partially offset by:
  - A $10 million increase due to favorable fuel adjustments.

- Margins from Off-system Sales decreased $4 million primarily due to lower physical sales volumes and lower trading and marketing margins.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $1 million primarily due to the following:
  - A $6 million increase in steam power expenses related to the Unit 1 fire outage. This increase was offset by an increase in Retail Margins as discussed above.

  This increase was partially offset by:
  - A $4 million decrease due to maintenance outages at the Tanners Creek and Rockport plants in 2011.
- Depreciation and Amortization expenses increased $4 million primarily due to higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life as approved in the Michigan base case settlement effective April 2012.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Reconciliation of Six Months Ended June 30, 2011 to Six Months Ended June 30, 2012
Net Income
(in millions)

Six Months Ended June 30, 2011	$	77
Changes in Gross Margin:		
Retail Margins		(20)
FERC Municipals and Cooperatives		(2)
Off-system Sales		(8)
Transmission Revenues		2
Other Revenues		5
Total Change in Gross Margin		(23)
Changes in Expenses and Other:		
Other Operation and Maintenance		5
Depreciation and Amortization		(4)
Taxes Other Than Income Taxes		2
Interest Expense		(1)
Total Change in Expenses and Other		2
Income Tax Expense		13
Six Months Ended June 30, 2012	$	69

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 $20 million primarily due to the following:
  - A $29 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 $9 million decrease primarily due to lower commercial prices and lower residential usage.
  - A $7 million decrease in weather-related usage primarily due to a 32% decrease in heating degree days.

  These decreases were offset by:
  - A $19 million increase in rate recovery primarily due to higher PJM rider revenue, Michigan base rate increases and higher Indiana Demand Side Management (DSM) revenue. The increase in PJM and DSM revenues is offset by a corresponding increase in Other Operation and Maintenance expenses as discussed below.
  - A $6 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 $2 million primarily due to the following:

  - A $10 million decrease due to an annual base rate adjustment to actual costs.

  This decrease was partially offset by:

  - An $8 million increase due to favorable fuel adjustments.

- Margins from Off-system Sales decreased $8 million primarily due to lower physical sales volumes and lower trading and marketing margins.
- Other Revenues increased $5 million primarily due to increased I&M's River Transportation Division (RTD) revenues from barging activities. This increase in RTD revenue was offset by a corresponding increase in Other Operation and Maintenance expenses from barging activities as discussed below.

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

- Other Operation and Maintenance expenses decreased $5 million primarily due to the following:
  - A $10 million decrease due to maintenance outages at the Tanners Creek and Rockport plants in 2011.
  - A $5 million decrease in distribution expenses primarily due to decreased overhead line expenses.

  These decreases were partially offset by:
  - A $6 million increase in steam power expenses related to the Unit 1 fire outage. This increase was offset by a corresponding increase in Retail Margins as discussed above.
  - A $4 million increase in PJM and DSM expenses. The increase in PJM and DSM expenses was offset by a corresponding increase in Retail Margins as discussed above.
  - A $2 million increase in RTD expenses from barging activities. The increase in RTD expense was offset by a corresponding increase in Other Revenues from barging activities as discussed above.
- Depreciation and Amortization expenses increased $4 million primarily due to higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life as approved in the Michigan base case settlement effective April 2012.
- Income Tax Expense decreased $13 million primarily due to a decrease in pretax book income, 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 201 for a discussion of accounting pronouncements.

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

	Three Months Ended		Six Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$435,965	$419,627	$871,992	$876,489
Sales to AEP Affiliates	45,728	70,902	121,643	145,770
Other Revenues - Affiliated	29,052	28,133	59,763	52,464
Other Revenues - Nonaffiliated	131	2,816	3,685	7,247
TOTAL REVENUES	510,876	521,478	1,057,083	1,081,970
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	96,715	108,322	209,085	223,384
Purchased Electricity for Resale	29,488	31,796	65,398	61,088
Purchased Electricity from AEP Affiliates	82,188	82,967	170,141	162,551
Other Operation	134,274	132,846	269,490	266,057
Maintenance	47,244	47,536	89,509	98,536
Depreciation and Amortization	37,560	33,263	71,539	67,350
Taxes Other Than Income Taxes	18,604	20,397	40,793	42,659
TOTAL EXPENSES	446,073	457,127	915,955	921,625
OPERATING INCOME	64,803	64,351	141,128	160,345
Other Income (Expense):				
Other Income	2,848	3,467	7,110	7,362
Interest Expense	(25,373)	(24,193)	(50,426)	(49,384)
INCOME BEFORE INCOME TAX EXPENSE	42,278	43,625	97,812	118,323
Income Tax Expense	12,468	12,239	28,781	41,510
NET INCOME	29,810	31,386	69,031	76,813
Preferred Stock Dividend Requirements	-	85	-	170
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$29,810	$31,301	$69,031	$76,643

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	Three Months Ended		Six Months Ended	
	2012	2011	2012	2011
Net Income	$ 29,810	$ 31,386	$ 69,031	$ 76,813
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of ($4,002) and $284 for the Three Months Ended June 30, 2012 and 2011, Respectively, and ($2,680) and $570 for the Six Months Ended June 30, 2012 and 2011, Respectively	(7,433)	528	(4,977)	1,059
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $150 and $127 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $300 and $255 for the Six Months Ended June 30, 2012 and 2011, Respectively	278	236	557	473
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(7,155)	764	(4,420)	1,532
TOTAL COMPREHENSIVE INCOME	$ 22,655	$ 32,150	$ 64,611	$ 78,345

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 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			(37,500)		(37,500)
Preferred Stock Dividends			(170)		(170)
Subototal – Common Shareholder's Equity					1,656,679
Net Income			76,813		76,813
Other Comprehensive Income				1,532	1,532
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2011	$ 56,584	$ 981,294	$ 716,503	$ (19,357)	$ 1,735,024
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 56,584	$ 980,896	$ 751,721	$ (28,221)	$ 1,760,980
Common Stock Dividends			(25,000)		(25,000)
Subototal – Common Shareholder's Equity					1,735,980
Net Income			69,031		69,031
Other Comprehensive Loss				(4,420)	(4,420)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2012	$ 56,584	$ 980,896	$ 795,752	$ (32,641)	$ 1,800,591

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 898	$ 1,020
Advances to Affiliates	238,466	95,714
Accounts Receivable:		
Customers	67,410	72,461
Affiliated Companies	69,138	90,980
Accrued Unbilled Revenues	19,088	14,780
Miscellaneous	13,631	22,685
Allowance for Uncollectible Accounts	(1,725)	(1,750)
Total Accounts Receivable	167,542	199,156
Fuel	68,321	52,979
Materials and Supplies	170,538	175,924
Risk Management Assets	39,058	32,152
Accrued Tax Benefits	16,769	38,425
Deferred Cook Plant Fire Costs	64,435	63,809
Prepayments and Other Current Assets	41,256	35,395
TOTAL CURRENT ASSETS	807,283	694,574
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,932,503	3,932,472
Transmission	1,261,018	1,224,786
Distribution	1,506,629	1,481,608
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	667,272	709,558
Construction Work in Progress	254,149	236,096
Total Property, Plant and Equipment	7,621,571	7,584,520
Accumulated Depreciation, Depletion and Amortization	3,196,749	3,179,920
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,424,822	4,404,600
OTHER NONCURRENT ASSETS		
Regulatory Assets	599,542	602,979
Spent Nuclear Fuel and Decommissioning Trusts	1,657,502	1,591,732
Long-term Risk Management Assets	31,408	29,362
Deferred Charges and Other Noncurrent Assets	64,510	69,309
TOTAL OTHER NONCURRENT ASSETS	2,352,962	2,293,382
TOTAL ASSETS	$ 7,585,067	$ 7,392,556

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 78,758	$ 113,063
Affiliated Companies	65,145	81,102
Long-term Debt Due Within One Year – Nonaffiliated		
(June 30, 2012 and December 31, 2011 Amounts Include $125,241 and		
$101,620, Respectively, Related to DCC Fuel)	303,240	279,075
Risk Management Liabilities	34,239	16,980
Customer Deposits	30,543	30,696
Accrued Taxes	63,380	65,233
Accrued Interest	27,839	27,798
Other Current Liabilities	85,437	117,879
TOTAL CURRENT LIABILITIES	688,581	731,826
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,828,261	1,778,600
Long-term Risk Management Liabilities	15,908	18,871
Deferred Income Taxes	968,806	925,712
Regulatory Liabilities and Deferred Investment Tax Credits	955,482	875,202
Asset Retirement Obligations	1,039,442	1,013,122
Deferred Credits and Other Noncurrent Liabilities	287,996	288,243
TOTAL NONCURRENT LIABILITIES	5,095,895	4,899,750
TOTAL LIABILITIES	5,784,476	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	795,752	751,721
Accumulated Other Comprehensive Income (Loss)	(32,641)	(28,221)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,800,591	1,760,980
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,585,067	$ 7,392,556

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 69,031	$ 76,813
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	71,539	67,350
Deferred Income Taxes	40,899	42,561
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(9,163)	23,086
Allowance for Equity Funds Used During Construction	(5,335)	(7,440)
Mark-to-Market of Risk Management Contracts	(2,798)	6,183
Amortization of Nuclear Fuel	64,228	72,474
Fuel Over/Under-Recovery, Net	(2,650)	2,947
Change in Other Noncurrent Assets	6,849	4,433
Change in Other Noncurrent Liabilities	42,793	12,055
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	31,614	74,240
Fuel, Materials and Supplies	(8,475)	26,103
Accounts Payable	(33,573)	(76,440)
Accrued Taxes, Net	19,642	13,775
Other Current Assets	(9,183)	(887)
Other Current Liabilities	(26,557)	(321)
Net Cash Flows from Operating Activities	248,861	336,932
INVESTING ACTIVITIES		
Construction Expenditures	(137,473)	(133,064)
Change in Advances to Affiliates, Net	(142,752)	-
Purchases of Investment Securities	(544,981)	(492,162)
Sales of Investment Securities	516,579	464,688
Acquisitions of Nuclear Fuel	(11,263)	(93,230)
Other Investing Activities	26,692	17,125
Net Cash Flows Used for Investing Activities	(293,198)	(236,643)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	128,533	76,624
Change in Advances from Affiliates, Net	-	(18,232)
Retirement of Long-term Debt – Nonaffiliated	(55,995)	(116,526)
Principal Payments for Capital Lease Obligations	(3,490)	(4,317)
Dividends Paid on Common Stock	(25,000)	(37,500)
Dividends Paid on Cumulative Preferred Stock	-	(170)
Other Financing Activities	167	25
Net Cash Flows from (Used for) Financing Activities	44,215	(100,096)

Net Increase (Decrease) in Cash and Cash Equivalents		(122)		193
Cash and Cash Equivalents at Beginning of Period		1,020		361
Cash and Cash Equivalents at End of Period	$	898	$	554
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	48,565	$	47,401
Net Cash Paid (Received) for Income Taxes		(31,921)		(19,847)
Noncash Acquisitions Under Capital Leases		4,341		1,218
Construction Expenditures Included in Current Liabilities at June 30,		26,509		36,109
Acquisition of Nuclear Fuel Included in Current Liabilities at June 30,		14		-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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 146.

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.

Proposed June 2012 – May 2015 Ohio ESP

In March 2012, OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing. The SSO rates would be effective through May 2015. The ESP will transition OPCo to an auction-based SSO for capacity and energy by June 2015. The ESP also proposed to collect the Phase-In Recovery Rider from June 2013 through December 2018. Further, the ESP proposed establishment of a non-bypassable Distribution Investment Rider through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The filing also seeks establishment of a new non-bypassable Retail Stability Rider (RSR) to recover lost generation revenues to provide financial certainty and stability during the ESP transition period. The proposed RSR would be effective through May 2015. Finally, the ESP proposed a storm damage recovery mechanism for the deferral of operation and maintenance costs above $5 million, effective January 2012.

Intervenors and the PUCO staff filed testimony in May 2012 in opposition to many aspects of OPCo's ESP, including the proposed RSR and the two-tiered capacity pricing structure for CRES providers. In addition, the PUCO staff's testimony included a proposal to increase the vegetation management base used for calculating over/under recovery on incremental vegetation spend from $21 million to $39 million, which could increase future Other Operation and Maintenance expense by $18 million on an annual basis. A decision from the PUCO is expected in August 2012. 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 second quarter of 2011 and the first six months of 2011, OPCo lost approximately $64 million and $112 million, respectively, of gross margin. OPCo is recovering a portion of lost margins through collection of capacity revenues from CRES providers and off-system sales. OPCo has lost 34% of its load to CRES providers.

Ohio Capacity Rate

In March 2012, in response to OPCo's motion for relief, the PUCO ordered that CRES providers not qualifying for the tier one capacity billing rate of $146/MW day, which is substantially below OPCo's current capacity cost of approximately $355/MW day, will pay a tier two capacity billing rate of $255/MW day. In July 2012, the PUCO issued an order in the capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer 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 pending June 2012 – May 2015 ESP proceeding. The PUCO postponed implementation of the order until August 8, 2012 or until an order is issued in OPCo's pending June 2012 – May 2015 ESP proceeding, whichever is sooner. In July 2012, OPCo requested rehearing of the PUCO order. See "Ohio Electric Security Plan Filing" section of

Note 2.

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. Additional filings at the FERC and other state commissions related to corporate separation are expected to be filed in the future.

If all regulatory approvals are received, OPCo's results of operations related to generation will be determined by its ability to sell power and capacity at a profit at rates determined by the prevailing market. If OPCo is unable to sell power and capacity at a profit, it could reduce future net income and cash flows and impact financial condition. A decision is pending from the PUCO.

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. It is unknown at this time 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. Management intends to file an application to terminate the Interconnection Agreement with the FERC in the future. 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.

Storm Damage

In late June 2012 and early July 2012, OPCo was significantly impacted by several severe storms. In the second quarter of 2012, OPCo incurred minimal incremental operation and maintenance expenses related to the June 2012 storms. OPCo expects to incur an estimated $100 million in total storm restoration costs in the third quarter of 2012, including an estimated $35 million in capital spending related to these storms and an estimated $65 million in incremental operation and maintenance costs. OPCo intends to defer the majority of the incremental operation and maintenance costs and seek future recovery. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

Securitization of Regulatory Assets

OPCo plans to file, in the third quarter of 2012, an application with the PUCO requesting securitization of the Distribution Asset Recovery Rider (DARR) balance. As of June 30, 2012, OPCo's DARR balance was $309 million, including $145 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018.

Significantly Excessive Earnings Test

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off of certain pretax earnings in 2010 and a subsequent refund to customers during 2011. In May 2011, the Industrial Energy Users-Ohio and the Ohio Energy Group (OEG) 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 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 on July 31, 2012 or one month after the PUCO issues an order on the 2010 SEET, whichever is later. 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. Because the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In March 2012, OPCo filed an application with the PUCO to approve an ESP for the period June 2012 through May 2015, which includes a request for a new DIR. A decision in the June 2012 – May 2015 ESP proceeding is expected in August 2012. In March 2012, the PUCO issued an order clarifying that OPCo has the right to file a new distribution base rate case. See “2011 Ohio Distribution Base Rate Case” section of Note 2.

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 146. 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 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions of KWHs)			
Retail:				
Residential	3,002	3,141	6,881	7,592
Commercial	3,582	3,512	6,818	6,901
Industrial	4,799	4,815	9,520	9,355
Miscellaneous	27	28	58	63
Total Retail (a)	11,410	11,496	23,277	23,911
Wholesale	2,798	2,911	5,304	5,682
Total KWHs	14,208	14,407	28,581	29,593

(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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in degree days)			
Actual - Heating (a)	146	161	1,543	2,234
Normal - Heating (b)	195	198	2,112	2,101

Actual - Cooling (c)	401	323	428	324
Normal - Cooling (b)	270	266	273	268

(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.

Second Quarter of 2012 Compared to Second Quarter of 2011

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

Second Quarter of 2011	$	142
Changes in Gross Margin:		
Retail Margins		(98)
Off-system Sales		12
Transmission Revenues		10
Other Revenues		10
Total Change in Gross Margin		(66)
Changes in Expenses and Other:		
Other Operation and Maintenance		25
Depreciation and Amortization		(7)
Taxes Other Than Income Taxes		(3)
Carrying Costs Income		(5)
Other Income		(1)
Interest Expense		3
Total Change in Expenses and Other		12
Income Tax Expense		13
Second Quarter of 2012	$	101

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 $98 million primarily due to the following:
  - A $70 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 $48 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 the third quarter of 2011.
  - A $13 million net decrease in regulated revenue primarily due to the elimination of POLR charges effective June 2011, resulting from an October 2011 PUCO remand order.

  These decreases were partially offset by:
  - A $35 million increase due to the partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
  - A $9 million increase in weather-related usage primarily due to a 24% increase in cooling degree days.
-

Margins from Off-system Sales increased $12 million primarily due to higher PJM capacity revenues, partially offset by lower physical sales volumes and lower trading and marketing margins.

- Transmission Revenues increased $10 million primarily due to increased transmission revenues for 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.
- Other Revenues increased $10 million primarily due to sales to Buckeye Power, Inc. to provide backup energy under the Cardinal Station Agreement and increased revenues from Cook Coal Terminal.

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

- Other Operation and Maintenance expenses decreased $25 million primarily due to the following:
  - A $28 million decrease in plant maintenance expenses at various plants.
  - A $4 million reserve recorded in second quarter of 2011 as a result of a legal proceeding.
  - A $3 million decrease in employee-related expenses.

  These decreases were partially offset by:
  - A $7 million increase in advertising expenses.
  - A $3 million increase due to expenses related to the 2012 sustainable cost reductions.
- Depreciation and Amortization expenses increased $7 million primarily due to the following:
  - An $18 million increase due to shortened depreciable lives for certain generating plants effective December 2011.
  - A $2 million increase in amortization of the Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case.

  These increases were partially offset by:
  - 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 $5 million decrease in depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.
- Carrying Costs Income decreased $5 million primarily due to a 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.
- Income Tax Expense decreased $13 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.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Reconciliation of Six Months Ended June 30, 2011 to Six Months Ended June 30, 2012
Net Income
(in millions)

Six Months Ended June 30, 2011	$	308
Changes in Gross Margin:		
Retail Margins		(201)
Off-system Sales		19
Transmission Revenues		17
Other Revenues		17
Total Change in Gross Margin		(148)
Changes in Expenses and Other:		
Other Operation and Maintenance		78
Depreciation and Amortization		(8)
Taxes Other Than Income Taxes		(3)
Carrying Costs Income		(13)
Interest Expense		6
Total Change in Expenses and Other		60
Income Tax Expense		32
Six Months Ended June 30, 2012	$	252

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 $201 million primarily due to the following:
  - A $124 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.
  - An $88 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 the third quarter of 2011.
  - A $17 million net decrease in regulated revenue primarily due to the elimination of POLR charges effective June 2011, resulting from an October 2011 PUCO remand order.
  - A $13 million decrease in weather-related usage primarily due to a 31% decrease in heating degree days.

  These decreases were partially offset by:
  - 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.
-

Margins from Off-system Sales increased $19 million primarily due to higher PJM capacity revenues, partially offset by lower physical sales volumes and lower trading and marketing margins.

- Transmission Revenues increased $17 million primarily due to increased transmission revenues for customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.
- Other Revenues increased $17 million primarily due to higher sales to Buckeye Power, Inc. to provide backup energy under the Cardinal Station Agreement and increased revenues from Cook Coal Terminal.

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

- Other Operation and Maintenance expenses decreased $78 million primarily due to the following:
  - A $40 million decrease in plant maintenance expenses at various plants.
  - A $35 million decrease due to 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 the Ohio modified stipulation.
  - A $10 million decrease in employee-related expenses.

  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 $3 million increase due to expenses related to the 2012 sustainable cost reductions.
- Depreciation and Amortization expenses increased $8 million primarily due to the following:
  - A $32 million increase due to shortened depreciable lives for certain generating plants effective December 2011.
  - A $5 million increase in amortization of the Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case.

  These increases were partially offset by:
  - A $19 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $10 million decrease in depreciation due to the third quarter 2011 plant impairment of Sporn Unit 5.
- Carrying Costs Income decreased $13 million primarily due to the following:
  - 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.
  - The collection of $3 million in carrying costs in first quarter 2012 on phase-in FAC deferrals.
  - A $3 million decrease due to line extension carrying charges recorded in 2011.
- Interest Expense decreased $6 million as a result of the reversal of capitalized interest on ESP Projects, an increase in the debt component of AFUDC as a result of new construction and the reversal of interest accruals related to federal tax reserve positions.
- Income Tax Expense decreased $32 million primarily due to a decrease 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 201 for a discussion of accounting pronouncements.

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

	Three Months Ended		Six Months Ended	
	2012	2011	2012	2011
REVENUES				
Electric Generation, Transmission and Distribution	$929,487	$1,041,528	$1,970,318	$2,171,705
Sales to AEP Affiliates	172,561	235,625	354,318	488,159
Other Revenues - Affiliated	7,979	4,507	17,090	11,525
Other Revenues - Nonaffiliated	3,723	3,898	9,247	8,359
TOTAL REVENUES	1,113,750	1,285,558	2,350,973	2,679,748
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	298,294	340,733	668,287	748,129
Purchased Electricity for Resale	52,104	68,983	110,238	137,397
Purchased Electricity from AEP Affiliates	81,818	127,894	170,501	244,345
Other Operation	162,086	159,553	292,428	329,952
Maintenance	74,015	102,030	154,619	195,442
Depreciation and Amortization	137,009	129,698	271,439	263,110
Taxes Other Than Income Taxes	98,420	95,133	203,838	200,443
TOTAL EXPENSES	903,746	1,024,024	1,871,350	2,118,818
OPERATING INCOME	210,004	261,534	479,623	560,930
Other Income (Expense):				
Interest Income	345	437	1,443	895
Carrying Costs Income	4,511	9,847	7,269	20,578
Allowance for Equity Funds Used During Construction	915	1,508	2,038	2,711
Interest Expense	(53,147)	(56,631)	(107,408)	(113,651)
INCOME BEFORE INCOME TAX EXPENSE	162,628	216,695	382,965	471,463
Income Tax Expense	61,205	74,501	130,712	163,299
NET INCOME	101,423	142,194	252,253	308,164
Preferred Stock Dividend Requirements Including Capital Stock Expense	-	208	-	416
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$101,423	$141,986	$252,253	$307,748

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	Three Months Ended		Six Months Ended	
	2012	2011	2012	2011
Net Income	$ 101,423	$ 142,194	$ 252,253	$ 308,164
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $91 and $122 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $846 and $280 for the Six Months Ended June 30, 2012 and 2011, Respectively	170	228	(1,571)	521
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,745 and $1,422 for the Three Months Ended June 30, 2012 and 2011, Respectively, and $3,490 and $2,844 for the Six Months Ended June 30, 2012 and 2011, Respectively	3,240	2,640	6,481	5,281
TOTAL OTHER COMPREHENSIVE INCOME	3,410	2,868	4,910	5,802
TOTAL COMPREHENSIVE INCOME	$ 104,833	$ 145,062	$ 257,163	$ 313,966

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 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			(325,000)		(325,000)
Preferred Stock Dividends			(366)		(366)
Capital Stock Expense		50	(50)		-
Subtotal – Common Shareholder's Equity					4,329,273
Net Income			308,164		308,164
Other Comprehensive Income				5,802	5,802
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2011	$ 321,201	$ 1,745,041	$ 2,751,350	$ (174,353)	$ 4,643,239
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 321,201	$ 1,744,099	$ 2,582,600	$ (197,722)	$ 4,450,178
Common Stock Dividends			(150,000)		(150,000)
Subtotal – Common Shareholder's Equity					4,300,178
Net Income			252,253		252,253
Other Comprehensive Income				4,910	4,910
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2012	$ 321,201	$ 1,744,099	$ 2,684,853	$ (192,812)	$ 4,557,341

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,366	$ 2,095
Advances to Affiliates	32,671	219,458
Accounts Receivable:		
Customers	116,264	146,432
Affiliated Companies	146,434	162,830
Accrued Unbilled Revenues	13,865	19,012
Miscellaneous	5,030	16,994
Allowance for Uncollectible Accounts	(3,712)	(3,563)
Total Accounts Receivable	277,881	341,705
Fuel	344,642	262,886
Materials and Supplies	191,005	201,325
Risk Management Assets	62,962	54,293
Accrued Tax Benefits	6,643	11,975
Prepayments and Other Current Assets	29,430	41,560
TOTAL CURRENT ASSETS	947,600	1,135,297
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	9,552,733	9,502,614
Transmission	1,971,788	1,948,329
Distribution	3,631,335	3,545,574
Other Property, Plant and Equipment	568,702	546,642
Construction Work in Progress	346,531	354,465
Total Property, Plant and Equipment	16,071,089	15,897,624
Accumulated Depreciation and Amortization	5,764,534	5,742,561
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,306,555	10,155,063
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,405,104	1,370,504
Long-term Risk Management Assets	66,290	53,614
Deferred Charges and Other Noncurrent Assets	193,784	309,775
TOTAL OTHER NONCURRENT ASSETS	1,665,178	1,733,893
TOTAL ASSETS	$ 12,919,333	$ 13,024,253

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 224,892	$ 293,730
Affiliated Companies	97,248	183,898
Long-term Debt Due Within One Year – Nonaffiliated	606,000	244,500
Risk Management Liabilities	35,141	36,561
Accrued Taxes	327,397	450,570
Accrued Interest	65,405	66,441
Other Current Liabilities	240,361	238,275
TOTAL CURRENT LIABILITIES	1,596,444	1,513,975
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,054,044	3,609,648
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	33,753	17,890
Deferred Income Taxes	2,323,655	2,245,380
Regulatory Liabilities and Deferred Investment Tax Credits	507,454	301,124
Employee Benefits and Pension Obligations	318,506	335,029
Deferred Credits and Other Noncurrent Liabilities	328,136	351,029
TOTAL NONCURRENT LIABILITIES	6,765,548	7,060,100
TOTAL LIABILITIES	8,361,992	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	2,684,853	2,582,600
Accumulated Other Comprehensive Income (Loss)	(192,812)	(197,722)
TOTAL COMMON SHAREHOLDER’S EQUITY	4,557,341	4,450,178
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,919,333	$ 13,024,253

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 146.

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

	2012	2011
OPERATING ACTIVITIES		
Net Income	$ 252,253	$ 308,164
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	271,439	263,110
Deferred Income Taxes	82,961	115,726
Carrying Costs Income	(7,269)	(20,578)
Allowance for Equity Funds Used During Construction		