AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 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 March 31, 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.

Large accelerated filer	X	Accelerated filer	

Non-accelerated filer		Smaller reporting company	

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

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

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

Yes		No	X

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants at April 26, 2012
American Electric Power Company, Inc.	484,321,794
	($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
March 31, 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 subsidiary 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 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.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, 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 and DCC Fuel IV LLC, variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC

	formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.

Term	Meaning
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.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SIA	

	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.

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Term	Meaning
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant under construction in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Financial Discussion and Analysis" of the 2011 Annual Report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve 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.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.

- 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 FINANCIAL DISCUSSION AND ANALYSIS

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 from June 2012 through May 2015. The ESP will transition OPCo to an auction-based SSO for capacity and energy by June 1, 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 will be effective through May 2015. Hearings are scheduled at the PUCO for May 2012 and oral arguments are scheduled for July 3, 2012, which would delay the proposed implementation of rates. See “Ohio Electric Security Plan Filing” section of Note 2.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As a result, in comparison to the first quarter of 2011, we lost approximately $42 million of gross margin. We are recovering a portion of lost margins through collection of capacity revenues from competitive 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. AEP Retail Energy Partners LLC targets retail customers in Ohio, both within and outside of our retail service territory.

In March 2012, AEP Retail Energy Partners LLC completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions. BlueStar 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. BlueStar has been in operation since 2002.

Ohio Capacity Rate

In March 2012, in response to OPCo’s motion for relief, the PUCO ordered that competitive retail electric service (CRES) providers not qualifying for the Reliability Pricing Model (RPM) price, which is substantially below OPCo’s current capacity cost of approximately $355/MW day, will pay a capacity billing rate of $255/MW day through May 2012, at which time the capacity billing rate will revert to the RPM price. If the PUCO does not issue an order in the June 2012 – May 2015 ESP proceeding by May 31, 2012, OPCo will request an extension of the $255/MW day capacity rate. See “Ohio Electric Security Plan Filing” section of Note 2.

Possible Corporate Separation and Termination of the Interconnection Agreement

In March 2012, we filed a corporate separation plan with the PUCO for OPCo’s generation assets. 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, APCo and KPCo will seek recovery of associated costs from customers through their regulated rates. 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.

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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.

Customer Demand

In comparison to the first quarter of 2011, heating degree days in 2012 were down 32% and 50% in our eastern and western service territories, respectively. Retail margins also decreased due to the loss of retail customers in Ohio. See “Ohio Customer Choice” section above. Our weather-normalized industrial sales increased 2% in 2012, primarily due to a significant increase in production from Ormet, a large aluminum company, and lesser increases from other metals and refinery customers.

Cost Reduction Initiatives

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 the redeployment of employees and involuntary severances. The process is expected to be completed by the end of 2012.

Securitization

Texas Securitization

As part of the Texas restructuring appeals, in December 2011, the PUCT approved an unopposed stipulation allowing TCC to recover $800 million, including carrying charges. We completed the securitization financing of $800 million in March 2012.

West Virginia Securitization

In March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances. APCo and WPCo anticipate filing, in the second quarter of 2012, a request for a financing order with the WVPSC pursuant to the securitization legislation. As of March 31, 2012, APCo’s ENEC under-recovery balance of $334 million was recorded in Regulatory Assets on the balance sheet. See “APCo’s and WPCo’s Expanded Net Energy Charge (ENEC) Filing” section of Note 2.

Regulatory Activity

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct the audit of the FAC for OPCo for the period of January 2009 through December 2009. 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 expects to record the favorable effect of the rehearing order of approximately $30 million in the second quarter of 2012.

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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. 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. OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. 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. Management does not currently believe that there are significantly excessive earnings in 2011 for either CSPCo or OPCo. See "Ohio Electric Security Plan Filing" section of Note 2.

Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense. Final hearings are currently scheduled for June 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 coal generating unit in Arkansas, which is on target 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.

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. 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. The installation of the new turbine rotors and other equipment occurred during the refueling outage of Unit 1 in the fall 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it 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.

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Life Cycle Management Project

In April 2012, I&M filed a petition with the IURC for approval of the Cook Plant Life Cycle Management Project (LCM Project). The LCM Project consists of a group of capital projects that extend the operating lives of Unit 1 and 2 to 2034 and 2037, respectively, which is consistent with the recent extension of their operating licenses. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. I&M requested recovery of certain project costs, including interest, through a rider effective 2013. I&M intends to file with the MPSC in the second quarter of 2012. As of March 31, 2012, I&M has incurred $74 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 March 31, 2012, the AEP System had a total generating capacity of nearly 37,080 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 RTO of our intent to retire the following plants or units of plants before or during 2015:

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 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.

Scrubber Applications

Rockport Plant

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit its Rockport Plant. As part of I&M's compliance plan to address new environmental requirements, I&M needs to install FGD and selective catalytic reduction equipment on one unit of the Rockport Plant. As a result of environmental requirements, I&M is evaluating options related to maturity of the lease for Rockport Plant Unit 2 in 2022. 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 third quarter of 2012.

Big Sandy Unit 2 FGD System

KPCo filed an application with the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system and to commence site construction activities on or about July 1, 2013. KPCo also filed for approval of its 2011 environmental compliance plan and related surcharge tariff for construction of certain facilities associated with the plan. The projected capital costs of the Big Sandy Unit 2 dry FGD system are approximately $955 million including certain preconstruction study costs and approximately $101 million of AFUDC. If approved, recovery of the Big Sandy Unit 2 dry FGD system would begin two months following the projected in-service date of July 2016. As of March 31, 2012, KPCo has incurred $25 million related to the project including $15 million associated with a previously studied wet FGD system. In March 2012, intervenors filed testimony which opposed the project. A decision is expected in second quarter of 2012. 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 go forward with the estimated $408 million FGD project at the Flint Creek Plant. As a joint owner of the Flint Creek Plant, SWEPCo's portion of the FGD project costs is estimated at $204 million.

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.

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 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.

The final rule contains a slightly less stringent PM limit 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.

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 and retirement of the second unit no later than 2026. The parties are working toward finalizing a settlement agreement.

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 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. Once the proposal is published in the Federal Register, the Federal EPA intends to solicit comments for 60 days. We will be evaluating the proposal and preparing comments to submit to the Federal EPA.

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.

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. We submitted comments on the proposal in July and August 2011. A final rule is expected to be signed by the Federal EPA Administrator by the end of July 2012. 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 CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

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. In March 2012, the court granted the defendants' motion for dismissal of the suit in "Carbon Dioxide Public Nuisance Claims" 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. 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.
- In April 2012, AEP and Great Plains Energy (Great Plains) formed Transource Energy LLC (Transource). AEP and Great Plains own 86.5% and 13.5% of Transource, respectively. Transource will initially pursue transmission projects in PJM, SPP and MISO.

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 months ended March 31, 2012 and 2011. We reclassified prior year amounts to conform to the current year's presentation.

	Three Months Ended March 31, 2012	2011
	(in millions)	
Utility Operations	$ 384	$ 374
Transmission Operations	9	4
AEP River Operations	9	7
Generation and Marketing	(1)	1
All Other (a)	(11)	(31)
Net Income	$ 390	$ 355

(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

First Quarter of 2012 Compared to First Quarter of 2011

Net Income increased from $355 million in 2011 to $390 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.
- Successful rate proceedings in our various jurisdictions.
- A first quarter 2011 settlement of litigation with BOA and Enron.
- An overall increase in net income from our Transmission Operations segment due to increased investments by ETT and our wholly-owned transmission subsidiaries.

These increases were partially offset by:

- A decrease in weather-related usage.
- The loss of retail customers in Ohio to various competitive retail electric service providers.

Average basic shares outstanding increased to 484 million in 2012 from 481 million in 2011. Actual shares outstanding were 484 million as of March 31, 2012.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross Margin represents total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power. We reclassified prior year amounts to conform to the current year’s presentation.

	Three Months Ended March 31, 2012	2011
	(in millions)	
Revenues	$ 3,385	$ 3,524
Fuel and Purchased Power	1,269	1,297
Gross Margin	2,116	2,227
Other Operation and Maintenance	755	850
Depreciation and Amortization	412	393
Taxes Other Than Income Taxes	211	209
Operating Income	738	775
Interest and Investment Income	1	2
Carrying Costs Income	20	15
Allowance for Equity Funds Used During Construction	20	20
Interest Expense	(217)	(232)
Income Before Income Tax Expense and Equity Earnings	562	580

Equity Earnings of Unconsolidated Subsidiaries	1	1
Income Tax Expense	179	207
Net Income	$ 384	$ 374

Summary of KWH Energy Sales for Utility Operations

	Three Months Ended March 31, 2012	2011
	(in millions of KWHs)	
Retail:		
Residential	14,799	16,949
Commercial	11,265	11,646
Industrial	14,647	14,329
Miscellaneous	721	723
Total Retail (a)	41,432	43,647
Wholesale	8,913	9,151
Total KWHs	50,345	52,798

(a) Includes energy delivered to customers served by TCC and TNC.

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 March 31, 2012	2011
	(in degree days)	
Eastern Region		
Actual - Heating (a)	1,261	1,854
Normal - Heating (b)	1,751	1,739
Actual - Cooling (c)	28	3
Normal - Cooling (b)	3	3
Western Region		
Actual - Heating (a)	347	692
Normal - Heating (b)	581	579
Actual - Cooling (d)	133	109
Normal - Cooling (b)	60	58

(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.

First Quarter of 2012 Compared to First Quarter of 2011

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

First Quarter of 2011	$	374
Changes in Gross Margin:		
Retail Margins		(98)
Off-system Sales		(2)
Transmission Revenues		13
Other Revenues		(24)
Total Change in Gross Margin		(111)
Changes in Expenses and Other:		
Other Operation and Maintenance		95
Depreciation and Amortization		(19)
Taxes Other Than Income Taxes		(2)
Interest and Investment Income		(1)
Carrying Costs Income		5
Interest Expense		15
Total Change in Expenses and Other		93
Income Tax Expense		28
First Quarter of 2012	$	384

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

· Retail Margins decreased $98 million primarily due to the following:
  · An $87 million decrease in weather-related usage primarily due to 32% and 50% decreases in heating degree days in our eastern and western service territories, respectively.
  · A $54 million decrease attributable to Ohio customers switching to alternative competitive retail electric service (CRES) providers.
  · A $39 million decrease due to the elimination of POLR charges, effective June 2011, in Ohio as a result of the October 2011 PUCO remand order.

  These decreases were partially offset by:
  · Successful rate proceedings in our service territories which include:
    · A $37 million rate increase for OPCo.
    · A $22 million rate increase for APCo.
    · A $16 million rate increase for I&M.
    · For the rate increases described above, $20 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.
· Margins from Off-system Sales decreased $2 million primarily due to lower physical sales volumes and lower trading and marketing margins, partially offset by an increase in PJM capacity revenues.
·

Transmission Revenues increased $13 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers partially offsets lost revenues included in Retail Margins above.

· Other Revenues decreased $24 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 $95 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 in March 2011.
  - 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 $34 million decrease in employee-related expenses.
  - A $27 million decrease in plant outage and other plant operating and maintenance expenses.

  These decreases were partially offset by:
  - A $33 million increase due to the first quarter 2011 deferral of 2009 costs related to storms and our 2010 cost reduction initiatives as allowed by the WVPSC in March 2011.
  - An $11 million gain from the sale of land in January 2011.
- Depreciation and Amortization expenses increased $19 million primarily due to the following:
  - A $14 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011.
  - A $6 million increase due to increased amortization of TCC's Securitized Transition Assets. The increase in TCC's securitization related amortizations are offset within Gross Margin.
  - A $6 million increase in depreciation as a result of APCo's increase in depreciation rates in Virginia effective February 1, 2012.
  - A $5 million increase in amortization primarily due to APCo's current year amortization 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 $9 million decrease due to the amortization of a portion of an Ohio distribution depreciation reserve as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case.
- Carrying Costs Income increased $5 million primarily due to the following:
  - 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.

  These increases were partially offset by:
  - An $8 million decrease primarily due to OPCo's collections of carrying costs in the first quarter 2012 on phase-in FAC deferrals and certain distribution regulatory assets.
- Interest Expense decreased $15 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense decreased $28 million primarily due to a decrease in pre-tax book income and audit settlements for previous years.

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TRANSMISSION OPERATIONS

First Quarter of 2012 Compared to First Quarter of 2011

Net Income from our Transmission Operations segment increased from $4 million in 2011 to $9 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

First Quarter of 2012 Compared to First Quarter of 2011

Net Income from our AEP River Operations segment increased from $7 million in 2011 to $9 million in 2012 primarily due to a reduction in expenses as a result of reduced spending.

GENERATION AND MARKETING

First Quarter of 2012 Compared to First Quarter of 2011

Net Income from our Generation and Marketing segment decreased from a gain of $1 million in 2011 to a loss of $1 million in 2012 primarily due to the expiration of production tax credits in 2011 partially offset by increased gross margins at the Oklaunion Plant.

ALL OTHER

First Quarter of 2012 Compared to First Quarter of 2011

Net Income from All Other increased from a loss of $31 million in 2011 to a loss of $11 million in 2012 primarily due to a loss incurred in February 2011 related to the settlement of litigation with BOA and Enron.

AEP SYSTEM INCOME TAXES

First Quarter of 2012 Compared to First Quarter of 2011

Income Tax Expense decreased $89 million primarily due to a decrease in pretax book income, the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron and audit settlements for previous years.

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

	March 31, 2012			December 31, 2011		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$ 17,320	52.1	%	$ 16,516	50.3	%
Short-term Debt	1,050	3.2		1,650	5.0	

Total Debt		18,370	55.3			18,166	55.3	
AEP Common Equity		14,856	44.7			14,664	44.7	
Noncontrolling Interests		1	-			1	-	
Total Debt and Equity Capitalization	$	33,227	100.0	%	$	32,831	100.0	%

Our ratio of debt-to-total capital was unchanged from December 31, 2011 to March 31, 2012 at 55.3%. 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 March 31, 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-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2012, our available liquidity was approximately $3 billion as illustrated in the table below:

			Amount (in millions)	Maturity
Commercial Paper Backup:				
	Revolving Credit Facility	$	1,500	June 2015
	Revolving Credit Facility		1,750	July 2016
Total			3,250	
Cash and Cash Equivalents			286	
Total Liquidity Sources			3,536	
Less:	AEP Commercial Paper Outstanding		385	
	Letters of Credit Issued		189	
Net Available Liquidity		$	2,962	

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 three months of 2012 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2012 was 0.47%.

Securitized Accounts Receivables

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

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 March 31, 2012, this contractually-defined percentage was 50.1%. Nonperformance under these covenants could result in an event of default under these credit agreements. At March 31, 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 March 31, 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 April 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.

	Three Months Ended March 31,	
	2012	2011
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 221	$ 294
Net Cash Flows from Operating Activities	876	830
Net Cash Flows Used for Investing Activities	(792)	(613)
Net Cash Flows from (Used for) Financing Activities	(19)	114

Net Increase in Cash and Cash Equivalents	65	331
Cash and Cash Equivalents at End of Period	$ 286	$ 625

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

Operating Activities

	Three Months Ended March 31, 2012	2011
	(in millions)	
Net Income	$ 390	$ 355
Depreciation and Amortization	423	403
Other	63	72
Net Cash Flows from Operating Activities	$ 876	$ 830

Net Cash Flows from Operating Activities were $876 million in 2012 consisting primarily of Net Income of $390 million and $423 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 weather. 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 $830 million in 2011 consisting primarily of Net Income of $355 million and $403 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 decreases in fuel inventory and receivables from customers and the unfavorable impact of reducing 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, 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. $211 million of this payment was to settle litigation with BOA and Enron. The remaining $214 million to acquire cushion gas is discussed in Investing Activities below.

Investing Activities

	Three Months Ended March 31, 2012	2011
	(in millions)	
Construction Expenditures	$ (741)	$ (540)
Acquisitions of Nuclear Fuel	(11)	(27)
Acquisitions of Assets/Businesses	(85)	(2)
Acquisition of Cushion Gas from BOA	-	(214)
Proceeds from Sales of Assets	8	69
Other	37	101
Net Cash Flows Used for Investing Activities	$ (792)	$ (613)

Net Cash Flows Used for Investing Activities were $792 million 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 $613 million 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

	Three Months Ended March 31, 2012	2011
	(in millions)	
Issuance of Common Stock, Net	$ 31	$ 31
Issuance of Debt, Net	193	324
Dividends Paid on Common Stock	(229)	(223)
Other	(14)	(18)
Net Cash Flows from (Used for) Financing Activities	$ (19)	$ 114

Net Cash Flows Used for Financing Activities in 2012 were $19 million. Our net debt issuances were $193 million. The net issuances included issuances of $800 million securitization bonds, $275 million of senior unsecured notes and $67 million of notes payable offset by retirements of $191 million of senior unsecured and other debt notes, $50 million of pollution control bonds, $98 million of securitization bonds and a decrease in short-term borrowing of $600 million. We paid common stock dividends of $229 million. See Note 10 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2011 were $114 million. Our net debt issuances were $324 million. The net issuances included $600 million senior unsecured notes, $421 million of pollution control bonds and an increase in short-term borrowing of $87 million offset by retirements of $214 million of senior unsecured and debt notes, $471 million of pollution control bonds and $92 million of securitization bonds. We paid common stock dividends of $223 million.

In April 2012, I&M retired $26 million of Notes Payable related to DCC Fuel.

In April 2012, I&M issued $110 million of variable rate Notes Payable related to DCC Fuel.

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including reducing operational expenses and spreading risk of loss to third parties. Our current 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:

	March 31, 2012	December 31, 2011
	(in millions)	
Rockport Plant Unit 2 Future Minimum Lease Payments	$ 1,626	$ 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, contingencies, 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 because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment 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)
Three Months Ended March 31, 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	2	(9)	(7)
Fair Value of New Contracts at Inception When Entered During the Period (a)	4	4	8
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	3	3	6
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	4	-	4
Total MTM Risk Management Contract Net Assets at March 31, 2012	$72	$130	202
Commodity Cash Flow Hedge Contracts			(26)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(15)
Fair Value Hedge Contracts			1
Collateral Deposits			85
Total MTM Derivative Contract Net Assets at March 31, 2012			$247

(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 March 31, 2012, our credit exposure net of collateral to sub investment grade counterparties was approximately 5.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of March 31, 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	$ 637	$ 4	$ 633	2	$ 240
Split Rating	-	-	-	-	-
Noninvestment Grade	11	-	11	1	11
No External Ratings:					
Internal Investment Grade	316	-	316	2	178
Internal Noninvestment Grade	55	11	44	1	34
Total as of March 31, 2012	$ 1,019	$ 15	$ 1,004	6	$ 463
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 March 31, 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

Three Months Ended March 31, 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 March 31, 2012 and December 31, 2011, the estimated EaR on our debt portfolio for the following twelve months was $24 million and $29 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2012 and 2011
(in millions, except per-share and share amounts)
(Unaudited)

	2012	2011
REVENUES		
Utility Operations	$3,363	$3,497
Other Revenues	262	233
TOTAL REVENUES	3,625	3,730
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	1,053	1,056
Purchased Electricity for Resale	260	275
Other Operation	656	686
Maintenance	262	265
Depreciation and Amortization	423	403
Taxes Other Than Income Taxes	217	213
TOTAL EXPENSES	2,871	2,898
OPERATING INCOME	754	832
Other Income (Expense):		
Interest and Investment Income	2	2
Carrying Costs Income	20	15
Allowance for Equity Funds Used During Construction	23	20
Interest Expense	(229)	(242)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	570	627
Income Tax Expense	189	278
Equity Earnings of Unconsolidated Subsidiaries	9	6
NET INCOME	390	355
Net Income Attributable to Noncontrolling Interests	1	1
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	389	354
Preferred Stock Dividend Requirements of Subsidiaries	-	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$389	$353
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	483,828,101	481,144,270
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.80	$0.73

WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	484,248,868	481,365,806
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.80	$0.73
CASH DIVIDENDS DECLARED PER SHARE	$0.47	$0.46

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 30.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2012 and 2011
(in millions)
(Unaudited)

	2012	2011
NET INCOME	$390	$355
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $6 in 2012 and $1 in 2011	(11)	1
Securities Available for Sale, Net of Tax of $1 in 2012 and $- in 2011	2	1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $4 in 2012 and $3 in 2011	7	6
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(2)	8
TOTAL COMPREHENSIVE INCOME	388	363
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	387	362
Preferred Stock Dividend Requirements of Subsidiaries	-	1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$387	$361

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 30.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 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	6	25				31
Common Stock Dividends				(222)		(1)	(223)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			(13)				(13)
SUBTOTAL – EQUITY							13,416
NET INCOME				354		1	355
OTHER COMPREHENSIVE INCOME					8		8
TOTAL EQUITY – MARCH 31, 2011	502	$ 3,263	$ 5,916	$ 4,973	$ (373)	$ -	$ 13,779
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665
Issuance of Common Stock	1	6	25				31
Common Stock Dividends				(228)		(1)	(229)
Other Changes in Equity			3	(1)			2
SUBTOTAL – EQUITY							14,469
NET INCOME				389		1	390
OTHER COMPREHENSIVE LOSS					(2)		(2)
TOTAL EQUITY – MARCH 31, 2012	505	$ 3,280	$ 5,998	$ 6,050	$ (472)	$ 1	$ 14,857

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 30.

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

	2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 286	$ 221
Other Temporary Investments		
(March 31, 2012 and December 31, 2011 amounts include $202 and $281, respectively, related to Transition Funding and EIS)	217	294
Accounts Receivable:		
Customers	616	690
Accrued Unbilled Revenues	78	106
Pledged Accounts Receivable – AEP Credit	896	920
Miscellaneous	114	150
Allowance for Uncollectible Accounts	(34)	(32)
Total Accounts Receivable	1,670	1,834
Fuel	780	657
Materials and Supplies	638	635
Risk Management Assets	246	193
Accrued Tax Benefits	47	51
Regulatory Asset for Under-Recovered Fuel Costs	75	65
Margin Deposits	70	67
Prepayments and Other Current Assets	185	165
TOTAL CURRENT ASSETS	4,214	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,309	24,938
Transmission	9,211	9,048
Distribution	14,944	14,783
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,836	3,780
Construction Work in Progress	2,923	3,121
Total Property, Plant and Equipment	56,223	55,670
Accumulated Depreciation and Amortization	18,791	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	37,432	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,291	6,026
Securitized Transition Assets	2,289	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,662	1,592
Goodwill	90	76
Long-term Risk Management Assets	425	403

Deferred Charges and Other Noncurrent Assets		1,499		1,346
TOTAL OTHER NONCURRENT ASSETS		11,256		11,070
TOTAL ASSETS	$	52,902	$	52,223

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 30.

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

	2012	2011
CURRENT LIABILITIES		
Accounts Payable	$ 978	$ 1,095
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	665	666
Other Short-term Debt	385	984
Total Short-term Debt	1,050	1,650
Long-term Debt Due Within One Year		
(March 31, 2012 and December 31, 2011 amounts include $316 and $293, respectively, related to Transition Funding, DCC Fuel and Sabine)	1,980	1,433
Risk Management Liabilities	185	150
Customer Deposits	301	289
Accrued Taxes	679	717
Accrued Interest	237	279
Regulatory Liability for Over-Recovered Fuel Costs	79	8
Other Current Liabilities	853	990
TOTAL CURRENT LIABILITIES	6,342	6,611
NONCURRENT LIABILITIES		
Long-term Debt		
(March 31, 2012 and December 31, 2011 amounts include $2,382 and $1,674, respectively, related to Transition Funding, DCC Fuel and Sabine)	15,340	15,083
Long-term Risk Management Liabilities	239	195
Deferred Income Taxes	8,493	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,469	3,195
Asset Retirement Obligations	1,500	1,472
Employee Benefits and Pension Obligations	1,739	1,801
Deferred Credits and Other Noncurrent Liabilities	923	974
TOTAL NONCURRENT LIABILITIES	31,703	30,947
TOTAL LIABILITIES	38,045	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 504,566,633 503,759,460					
(20,336,592 shares were held in treasury at March 31, 2012 and December 31, 2011)		3,280		3,274	
Paid-in Capital		5,998		5,970	
Retained Earnings		6,050		5,890	
Accumulated Other Comprehensive Income (Loss)		(472)		(470)	
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		14,856		14,664	
Noncontrolling Interests		1		1	
TOTAL EQUITY		14,857		14,665	
TOTAL LIABILITIES AND EQUITY	$	52,902	$	52,223	

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 30.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2012 and 2011
(in millions)
(Unaudited)

	2012	2011
OPERATING ACTIVITIES		
Net Income	$390	$355
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	423	403
Deferred Income Taxes	261	330
Gain on Settlement with BOA and Enron	-	(51)
Settlement of Litigation with BOA and Enron	-	(211)
Carrying Costs Income	(20)	(15)
Allowance for Equity Funds Used During Construction	(23)	(20)
Mark-to-Market of Risk Management Contracts	10	42
Amortization of Nuclear Fuel	34	34
Property Taxes	(49)	(52)
Fuel Over/Under-Recovery, Net	112	(27)
Change in Other Noncurrent Assets	(59)	(3)
Change in Other Noncurrent Liabilities	(47)	77
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	207	181
Fuel, Materials and Supplies	(126)	121
Accounts Payable	(26)	(126)
Accrued Taxes, Net	(30)	(96)
Other Current Assets	(15)	2
Other Current Liabilities	(166)	(114)
Net Cash Flows from Operating Activities	876	830
INVESTING ACTIVITIES		
Construction Expenditures	(741)	(540)
Change in Other Temporary Investments, Net	79	73
Purchases of Investment Securities	(353)	(454)
Sales of Investment Securities	334	484
Acquisitions of Nuclear Fuel	(11)	(27)
Acquisitions of Assets/Businesses	(85)	(2)
Acquisition of Cushion Gas from BOA	-	(214)
Proceeds from Sales of Assets	8	69
Other Investing Activities	(23)	(2)
Net Cash Flows Used for Investing Activities	(792)	(613)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	31	31
Issuance of Long-term Debt	1,132	1,014
Commercial Paper and Credit Facility Borrowings	21	318
Change in Short-term Debt, Net	(583)	244

Retirement of Long-term Debt	(339)	(777)
Commercial Paper and Credit Facility Repayments	(38)	(475)
Principal Payments for Capital Lease Obligations	(18)	(17)
Dividends Paid on Common Stock	(229)	(223)
Dividends Paid on Cumulative Preferred Stock	-	(1)
Other Financing Activities	4	-
Net Cash Flows from (Used for) Financing Activities	(19)	114
Net Increase in Cash and Cash Equivalents	65	331
Cash and Cash Equivalents at Beginning of Period	221	294
Cash and Cash Equivalents at End of Period	$286	$625
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$265	$250
Net Cash Paid (Received) for Income Taxes	(65)	2
Noncash Acquisitions Under Capital Leases	20	24
Construction Expenditures Included in Current Liabilities at March 31,	250	220
Noncash Assumption of Liabilities Related to Acquisitions	56	-

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 30.

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 months ended March 31, 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 March 31, 2012 and 2011 were $55 million and $33 million, respectively. See the tables below for the classification of Sabine’s assets and liabilities on our condensed balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium expense to the protected cell for the three months ended March 31, 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 and DCC Fuel IV LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC and DCC Fuel IV LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and began in January 2011. Payments on the DCC Fuel IV LLC lease are made quarterly and began in February 2012. Payments on the leases for the three months ended March 31, 2012 and 2011 were $17 million and $6 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48, 54, 54 and 54 month lease term, respectively. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our condensed balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our condensed balance sheets. See "Securitized Accounts Receivables – 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 March 31, 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 $2.3 billion and $1.6 billion at March 31, 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
March 31, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$75	$123	$130	$885	$141
Net Property, Plant and Equipment	167	159	-	-	-
Other Noncurrent Assets	57	98	6	1	2,343
Total Assets	$299	$380	$136	$886	$2,484
LIABILITIES AND EQUITY					
Current Liabilities	$48	$92	$51	$840	$248
Noncurrent Liabilities	251	288	67	1	2,218
Equity	-	-	18	45	18
Total Liabilities and Equity	$299	$380	$136	$886	$2,484

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 March 31, 2012 and 2011 were $14 million and $13 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:

	March 31, 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	-	54	-	52
Total Investment in DHLC	$ 9	$ 63	$ 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 March 31, 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:

	March 31, 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	11	11	10	10

Total Investment in PATH-WV	$ 30	$ 30	$ 29	$ 29

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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 March 31,			
	2012		2011	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 389		$ 353	
Weighted Average Number of Basic Shares Outstanding	483.8	$ 0.80	481.1	$ 0.73
Weighted Average Dilutive Effect of:				
Stock Options	-	-	0.1	-
Restricted Stock Units	0.4	-	0.2	-
Weighted Average Number of Diluted Shares Outstanding	484.2	$ 0.80	481.4	$ 0.73

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

Options to purchase 136,250 shares of common stock were outstanding at March 31, 2011 but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive. There were no antidilutive shares outstanding at March 31, 2012.

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

	March 31, 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		
Deferred Wind Power Costs	44	38
Environmental Rate Adjustment Clause	21	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	2	10
Other Regulatory Assets Not Yet Being Recovered	19	14
Total Regulatory Assets Not Yet Being Recovered	$161	$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.

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. Management does not currently believe that there are 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. In March 2012, OPCo filed a request for rehearing of the March 2012 order relating to the PIRR. As of March 31, 2012, the net PIRR deferral was $499 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.

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 competitive retail electric service (CRES) providers not qualifying for the Reliability Pricing Model (RPM) price, which is substantially below OPCo's current capacity cost of approximately $355/MW day, will pay a capacity billing rate of $255/MW day through May 2012, at which time the capacity billing rate will revert to the RPM price.

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 from June 2012 through May 2015. The ESP will transition OPCo to an auction-based SSO for capacity and energy by June 1, 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 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 PUCO and before the FERC. In those proceedings, OPCo is seeking a wholesale cost-based capacity rate, currently at approximately $355/MW day. Hearings on the capacity proceedings were held at the PUCO in April 2012.

The ESP also proposed to collect the PIRR 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 will be effective through May 2015.

Hearings on the June 2012 – May 2015 ESP are scheduled at the PUCO for May 2012 and oral arguments are scheduled for July 3, 2012, which would delay the proposed implementation of rates.

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).

Due to the February 2012 PUCO order which rejected the 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. The June 2012 – May 2015 ESP proceeding is currently pending. 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 the audit of the FAC for OPCo for the period of January 2009 through December 2009. In May 2010, 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. Further, the January 2012 PUCO order stated that a consultant be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of the consultant's recommendation. In 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 expects to record the favorable effect of the rehearing order of approximately $30 million in the second quarter of 2012. 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.

2010 and 2011 Fuel Adjustment Clause Audits

In May 2011, the PUCO-selected outside consultant issued its results of the 2010 FAC audit. The audit report 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. The 2011 FAC audit is in progress and an audit report is expected to be issued in the second quarter of 2012. As of March 31, 2012, the amount of OPCo's carrying costs that could potentially be at risk due to the 2010 and 2011 audits is estimated to be approximately $32 million, including $17 million of unrecognized equity carrying costs. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If PUCO orders result in a reduction in the carrying charges related to the FAC deferrals, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

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 March 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order and has incurred pre-construction costs. 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 on target to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.8 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $122 million for transmission, excluding AFUDC. As of March 31, 2012, excluding costs attributable to its joint owners and a $49 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.5 billion of expenditures (including AFUDC and capitalized interest of $243 million for generation and related transmission costs of $110 million). As of March 31, 2012, the joint owners and SWEPCo have contractual construction obligations of approximately $90 million (including related transmission costs of $6 million). SWEPCo's share of the contractual construction obligations is $67 million.

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. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In November 2011, the Texas Court of Appeals affirmed the PUCT's order in all respects. Motions for rehearing at the Texas Court of Appeals were denied in January 2012. 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 would materially reduce future net income and cash flows and materially impact financial condition.

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 are reflected in APCo's filing. As of March 31, 2012, APCo’s under-recovered fuel balance and non-incremental wind purchased power costs of $84 million were recorded in Regulatory Assets on the balance sheet. If the Virginia SCC were to disallow a portion of APCo’s deferred fuel costs, including any deferred wind purchased power costs, it would reduce future net income and cash flows.

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 the Virginia SCC's environmental RAC 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 March 31, 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. APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

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

In March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances. Also in March 2012, APCo and WPCo filed their fourth year ENEC application with the WVPSC which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral. 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 second quarter of 2012, a request for a financing order with the WVPSC pursuant to the securitization legislation. If the financing order is not issued, APCo and WPCo requested recovery of these costs in current rates. As of March 31, 2012, APCo's ENEC under-recovery balance of $334 million was recorded in Regulatory Assets on the balance sheet, excluding $7 million of unrecognized equity carrying costs. If the WVPSC were to disallow a portion of APCo's and WPCo's deferred ENEC costs, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a 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. 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 request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense. Final hearings are currently scheduled for June 2012.

Life Cycle Management Project

In April 2012, I&M filed a petition with the IURC for approval of the Cook Plant Life Cycle Management Project (LCM Project). The LCM Project consists of a group of capital projects that extend the operating lives of Unit 1 and 2 to 2034 and 2037, respectively, which is consistent with the recent extension of their operating licenses. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. I&M requested recovery of certain project costs, including interest, through a rider effective 2013. As of March 31, 2012, I&M has incurred $74 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

KPCo filed an application with the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system and to commence site construction activities on or about July 1, 2013. KPCo also filed for approval of its 2011 environmental compliance plan and related surcharge tariff for construction of certain facilities associated with the plan. The projected capital costs of the Big Sandy Unit 2 dry FGD system are approximately $955 million including certain preconstruction study costs and approximately $101 million of AFUDC. If approved, recovery of the Big Sandy Unit 2 dry FGD system would begin two months following the projected in-service date of July 2016. As of March 31, 2012, KPCo has incurred $25 million related to the project including $15 million associated with a previously studied wet FGD system. In March 2012, intervenors filed testimony which opposed the project. The Kentucky Industrial Utility Customers also opposed recovery of the costs associated with the wet FGD system study. A decision is expected in second quarter of 2012. 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 March 31, 2012, the maximum future payments for letters of credit issued under the credit facilities were $189 million with maturities ranging from April 2012 to April 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 $100 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 March 31, 2012, SWEPCo has collected approximately $54 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Other Current Liabilities and $38 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 March 31, 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. At March 31, 2012, the maximum potential loss for these lease agreements was approximately $15 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 $16 million and $18 million for I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 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 CO_2 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 CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. The court heard oral argument in November 2011. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's provision is approximately $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 March 31, 2012, we recorded $64 million in Prepayments and Other Current Assets on our condensed balance sheets representing amounts under NEIL insurance policies. Through March 31, 2012, I&M received payments from NEIL of $203 million for the cost incurred to date to repair the property damage and $185 million under an accidental outage policy.

The claims process with NEIL continues and includes a review of claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies, the timing of the unit’s return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) was among the companies named as defendants in some of these cases. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the dismissal of several cases involving AEP companies in Nevada to the Ninth Circuit Court of Appeals. We will continue to defend the cases on appeal. We believe the provision we have is adequate. We believe the remaining exposure is immaterial.

4. ACQUISITION AND DISPOSITION

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 potential 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 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. BlueStar has been in operation since 2002 and has approximately 23,000 customer accounts.

DISPOSITION

2011

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

During the three months ended March 31, 2011, TCC sold $5 million of transmission facilities to ETT. There were no gains or losses recorded on these sale transactions.

5. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the three months ended March 31, 2012 and 2011:

	Pension Plans Three Months Ended March 31, 2012	Pension Plans Three Months Ended March 31, 2011	Other Postretirement Benefit Plans Three Months Ended March 31, 2012	Other Postretirement Benefit Plans Three Months Ended March 31, 2011
	(in millions)			
Service Cost	$ 19	$ 18	$ 12	$ 11
Interest Cost	56	59	26	27
Expected Return on Plan Assets	(80)	(79)	(25)	(27)
Amortization of Prior Service Credit	-	-	(5)	-
Amortization of Net Actuarial Loss	37	30	14	7
Net Periodic Benefit Cost	$ 32	$ 28	$ 22	$ 18

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.
- In April 2012, AEP and Great Plains Energy (Great Plains) formed Transource Energy LLC (Transource). AEP and Great Plains own 86.5% and 13.5% of Transource, respectively. Transource will initially pursue transmission power projects in PJM, SPP and MISO.

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 months ended March 31, 2012 and 2011 and balance sheet information as of March 31, 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 March 31, 2012							
Revenues from:							
External Customers	$ 3,362	$ 1	$ 172	$ 85	$ 5	$ -	$ 3,625
Other Operating Segments	23	2	7	-	2	(34)	-
Total Revenues	$ 3,385	$ 3	$ 179	$ 85	$ 7	$ (34)	$ 3,625
Net Income (Loss)	$ 384	$ 9	$ 9	$ (1)	$ (11)	$ -	$ 390

Nonutility
Operations