AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 28, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended June 30, 2016
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 as of July 28, 2016
American Electric Power Company, Inc.	491,709,452 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
June 30, 2016

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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
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.
AEPRO	AEP River Operations, LLC.
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.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VI LLC, DCC Fuel VII LLC, DCC Fuel VIII LLC and DCC Fuel IX LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP’s competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.

ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.

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Term	Meaning
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between Parent and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	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.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Power Purchase and Sale Agreement.
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.
Registrants	SEC registrants: AEP, 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.

Term	Meaning
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
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.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
TRA	Tennessee Regulatory Authority.
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 Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant 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 the Registrants 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 Discussion and Analysis of Financial Condition and Results of Operations” of the 2015 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, management undertakes 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, growth or contraction within and changes in market demand and demographic patterns in AEP service territories.

Inflationary or deflationary interest rate trends.

Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.

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 competition, including competition for retail customers.

Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.

The cost of fuel and its transportation and the creditworthiness and performance of fuel suppliers and transporters.

Availability of necessary generation capacity and the performance of generation plants.

The ability to recover fuel and other energy costs through regulated or competitive electric rates.

The ability to build transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.

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 that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.

Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.

Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.

Resolution of litigation.

The ability to constrain operation and maintenance costs.

The ability to develop and execute a strategy based on a view regarding prices of electricity and gas.

Prices and demand for power generated and sold at wholesale.

Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.

The ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas and capacity auction returns.

Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

The market for generation in Ohio and PJM and the ability to recover investments in Ohio generation assets.
The ability to successfully and profitably manage competitive generation assets, including the evaluation and execution of strategic alternatives for these assets as some of the alternatives could result in a loss.
Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of debt.

The impact of volatility in the capital markets on the value of the investments held by the pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
Accounting pronouncements periodically issued by accounting standard-setting bodies.
Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of the 2015 Annual Report and in Part II of this report.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP’s website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP’s website is not part of this report.

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

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the second quarter of 2016 decreased by 0.4% from the second quarter of 2015. AEP's second quarter 2016 industrial sales decreased 4.0% compared to the second quarter of 2015 primarily due to decreased sales to customers in the manufacturing sector. Weather-normalized commercial and residential sales increased by 1.0% and 2.4% in the second quarter of 2016, respectively, from the second quarter of 2015.

AEP's weather-normalized retail sales volumes for the six months ended June 30, 2016 decreased by 0.3% compared to the six months ended June 30, 2015. AEP's industrial sales volumes for the six months ended June 30, 2016 decreased 1.6% compared to the six months ended June 30, 2015 primarily due to decreased sales to customers in the manufacturing sector. Weather-normalized residential and commercial sales increased by 0.1% and 0.8%, respectively, for the six months ended June 30, 2016 compared to six months ended June 30, 2015.

June 2015 - May 2018 ESP Including PPA Application and Proposed ESP Extension through 2024

In March 2016, a contested stipulation agreement related to the PPA rider application was modified and approved by the PUCO. The approved PPA rider is effective April 2016 through May 2024, with quarterly PPA rider reconciliations to actual PPA costs compared to PJM market revenues, subject to audit and review by the PUCO. The stipulation agreement, as approved, included:

(a) an affiliate PPA between OPCo and AGR to be included in the PPA rider,
(b) OPCo's OVEC contractual entitlement (OVEC PPA) to be included in the PPA rider,
(c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider,
(d) a temporary customer-specific rate impact cap of 5% through May 2018,
(e) an agreement to retire, refuel or repower to 100% natural gas, Conesville Plant, Units 5 and 6 and Cardinal Plant, Unit 1 by 2029 and 2030, respectively,
(f) a directive that OPCo will not seek recovery from customers for any costs associated with the retirement, refueling, co-firing or repowering of PPA units,
(g) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider,
(h) the right for the PUCO to exclude costs associated with a forced outage lasting longer than 90 days and
(i) the right for the PUCO to re-evaluate or modify the PPA rider if there is a change to PJM's tariffs or rules that prohibits a PPA unit from being bid into PJM auctions.

Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MW and a wind energy project(s) of at least 500 MW, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. OPCo agreed to file a carbon reduction plan with the PUCO by December 2016 that will focus on fuel diversification and carbon emission reductions.

In March 2016, a group of merchant generation owners filed a complaint at the FERC against PJM seeking revisions to the Minimum Offer Price Rule (MOPR) in PJM's tariff. Although the complaint requested the FERC act in advance of the May 2016 Base Residual Auction for the 2019/2020 delivery year, the complaint is still pending without a decision from the FERC. If approved as proposed, the revised MOPR could affect future bidding behavior for units with cost recovery mechanisms.

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In April 2016, the FERC issued an order granting a January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo cannot implement the affiliate PPA without the FERC review, in accordance with FERC's rules governing affiliate transactions. As a result of the April 2016 FERC order, management does not intend to pursue the affiliate PPA.

In May 2016, OPCo filed an application for rehearing with the PUCO related to certain aspects of the March 2016 PUCO order. The application included a proposed OVEC-only PPA Rider that included an option for the rider to be bypassable. The proposed OVEC-only PPA Rider included (a) the elimination of the PUCO-imposed customer-specific rate impact cap of 5% through May 2018, (b) modifications to proportionately decrease the amount of the potential customer credits and (c) the inclusion of PJM capacity performance penalties within the PPA rider. Also in May 2016, intervenors filed applications for rehearing with the PUCO opposing the modified and approved stipulation agreement.

Management seeks to maintain, subject to requested modifications, the commitments approved as part of the original PPA order despite the fact that the proposed affiliate PPA is no longer included following the FERC's order rescinding the waiver of affiliate rules. OPCo has the option to exercise its right to withdraw from the PPA stipulation at any time.

Consistent with the terms of the modified and approved stipulation agreement, in May 2016, OPCo filed an amended ESP that proposed to extend the ESP through May 2024. The amended ESP included (a) an extension of the PPA rider, which includes only OPCo's entitlements to its ownership percentage of OVEC, (b) a proposed 10.41% return on common equity, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's Distribution Investment Rider and (e) the addition of various new riders, including a Generation Resource Rider.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filings" section of Note 4.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital (WACC) rate. In June 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue. In October 2015 this matter was remanded back to the PUCO for reinstatement of the WACC rate.

In May 2016, OPCo filed a proposed increase to the PIRR rates with the PUCO, in accordance with the June 2015 Supreme Court of Ohio ruling. The proposed increase to PIRR rates included $146 million in additional carrying charges and $40 million in additional under-recovered fuel costs resulting from a decrease in customer demand. OPCo requested the proposed increase be effective July 2016 through December 2018. In June 2016, the PUCO issued an order that approved OPCo's proposed increase to the PIRR rates.

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June 2012 - May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that established base generation rates through May 2015. In 2013, this ruling was generally upheld in PUCO rehearing orders.

In July 2012, the PUCO issued an order in a separate capacity proceeding requiring OPCo to charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which included reserve margins, was approximately $34/MW day through May 2014 and $150/MW day from June 2014 through May 2015. In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo’s capacity charges. In one of the opinions, the Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo’s authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period. The PUCO reduced OPCo’s authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo’s arguments that the $147.41/MW day credit was overstated by approximately $100/MW day due to various inaccuracies affecting input data and assumptions.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April 2015, the PUCO issued an order that modified and approved, OPCo’s July 2014 application to collect the unrecovered portion of the deferred capacity costs. As of June 30, 2016, OPCo’s net deferred capacity costs balance was $285 million, including debt carrying costs. In April 2016, the second Supreme Court of Ohio opinion rejected a portion of OPCo’s RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to reduce OPCo’s deferred capacity costs by these previously collected RSR revenues. The Supreme Court of Ohio was not able to determine the amount of the reduction to OPCo’s deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction. As directed by the PUCO, in May 2016, OPCo submitted revised RSR tariffs that reflect the RSR being collected subject to refund.

In April 2016, the Supreme Court of Ohio also ruled favorably on OPCo’s cross-appeal regarding a previously PUCO-imposed SEET threshold under the ESP and remanded this issue to the PUCO. See “Significantly Excessive Earnings Test Filings” section of Note 4.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In November 2013, the PUCO issued an order approving OPCo’s competitive bid process with modifications. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report with the PUCO for the period August 2012 through May 2015. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo’s $188.88/MW day capacity charge, the independent auditor has recommended a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and disagrees with the findings in the audit report.

In June 2016, OPCo filed a request with the PUCO that requested a consolidated procedural schedule to resolve interrelated proceedings including (a) OPCo's deferral of capacity costs for the period August 2012 through May 2015, (b) the implementation of OPCo's RSR and (c) the concerns related to the recovery of fixed fuel costs through both the FAC and the approved capacity charges. As part of the filing, OPCo requested that its net deferred capacity costs

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balance as of May 31, 2015 increase by $157 million, including carrying charges through September 2016. This net increase consists of a $327 million decrease due to the non-deferral portion of the RSR collections and an increase of $484 million for the correction of the energy credit. Recovery of the $157 million was requested to be effective October 2016 through December 2018. Additionally, OPCo filed testimony supporting the position that double recovery of fixed fuel costs could not have occurred because OPCo was unable to fully recover its capacity costs, which included fixed fuel costs, even with a corrected energy credit.

Due to the interrelated nature of these two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, management believes that the PUCO will rule upon these issues together. Further, management believes that the net impact of these issues will not result in a material future reduction of OPCo's net income.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filings" section of Note 4.

Merchant Fleet Alternatives

AEP is evaluating strategic alternatives for AGR's merchant generation fleet, included in the Generation & Marketing segment, as well as AEGCo's Lawrenceburg Plant, all of which operate in PJM. Potential alternatives may include, but are not limited to, continued ownership of the merchant generation fleet or a sale of the merchant generation fleet. In March 2016, AEP initiated a process to explore the sale of Darby, Gavin, Lawrenceburg and Waterford Plants totaling 5,326 MWs. Binding bids are anticipated in the third quarter of 2016. As of June 30, 2016, the net book value of these assets, including related materials and supplies inventory and CWIP, was $1.7 billion.

Management has not made a decision regarding the potential alternatives for AGR's remaining 2,732 MWs of merchant generation, nor has management set a specific time frame for a decision. As of June 30, 2016, the net book value of these assets, including related materials and supplies inventory and CWIP, was $2 billion. These alternatives could result in a loss which could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana, and through SWEPCo's wholesale customers under FERC-based rates.

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC would review base rates in 2014 and 2015 and that SWEPCo would recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for November 2016. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition. See the “2012 Louisiana Formula Rate Filing” section of Note 4.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could cost approximately $850 million, excluding AFUDC. As part of this investment, SWEPCo has completed construction of the environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $370 million, excluding AFUDC. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of June 30, 2016, SWEPCo had incurred costs of $389 million, including AFUDC, and had remaining contractual construction obligations of $20 million related to these projects. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. SWEPCo will seek recovery of the remaining project costs from customers at the state commissions and the FERC. See “Mercury and Other Hazardous Air Pollutants (HAPs) Regulation” and “Climate Change, CO_2 Regulation and Energy Policy” sections of “Environmental Issues” below.

As of June 30, 2016, the net book value of Welsh Plant, Units 1 and 3 was $631 million, before cost of removal, including materials and supplies inventory and CWIP. In April 2016, Welsh Plant, Unit 2 was retired. Upon retirement, $76 million was reclassified as Regulatory Assets on the balance sheet related to the net book value of Welsh Plant, Unit 2 and the related asset retirement obligation costs. Management will seek recovery of the remaining regulatory assets in future rate proceedings.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan for the Federal EPA’s Regional Haze Rule and Mercury and Air Toxics Standards, and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 of Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% effective in January 2016. The proposed $44 million increase related to environmental investments was effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed in service. The total estimated cost of the environmental controls to be installed at Northeastern Plant, Unit 3 and the Comanche Plant is $219 million, excluding AFUDC. As of June 30, 2016, PSO had incurred costs of $179 million and $41 million, including AFUDC, for Northeastern Plant, Unit 3 and Comanche Plant, respectively.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC. In April 2016, Northeastern Plant, Unit 4 was retired. Upon retirement, $87 million was reclassified as Regulatory Assets on the balance sheet related to the net book value of Northeastern Plant, Unit 4. These regulatory assets are pending regulatory approval.

In June 2016, an Administrative Law Judge (ALJ) issued a report related to PSO's base rate case filing. The ALJ recommended a 9.25% return on common equity. The ALJ found that PSO's environmental compliance plan is prudent, but had conflicting recommendations regarding cost recovery in this case and recommended an investment cap of $210 million on environmental controls installed at Northeastern Plant, Unit 3. Additionally, the ALJ recommendations included (a) a $17 million increase in depreciation expense, (b) continued depreciation of Northeastern Plant, Units 3 and 4 through 2040 (no accelerated depreciation), (c) return of, but no return on, the remaining net book value of Northeastern Plant, Unit 4, (d) disallowance of the requested environmental consumables through the FAC indicating that these amounts are not considered fuel and should be recovered through base rates in the next base rate case, (e) elimination of the rider to recover advanced metering starting in December 2016, without inclusion in base rates and (f) elimination of the system reliability rider through consolidation in base rates, without addressing a transition for recovery of rider costs, including deferred costs.

In June 2016, PSO, the OCC staff, the Attorney General and intervenors filed exceptions to the ALJ report. In July 2016, the OCC ordered the ALJ to submit a supplemental report clarifying the recommendations.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the "2015 Oklahoma Base Rate Case" section of Note 4.

2016 West Virginia Expanded Net Energy Cost Filing

In March 2016, APCo and WPCo filed their combined annual ENEC filing with the WVPSC. In June 2016, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC. The proposed settlement included $38 million of additional ENEC revenues and $17 million in construction surcharges annually for two years, effective July 2016. Additionally, APCo and WPCo agreed that a general rate case will not be filed before April 2018. In June 2016, the WVPSC approved the settlement agreement. See the "2016 West Virginia Expanded Net Energy Charge Filing" section of Note 4.

West Virginia Deferred Base Rate Increase

In May 2015, the WVPSC issued an order on APCo and WPCo's combined base rate case. The order included a delayed billing of $25 million of the annual base rate increase to residential customers until July 2016. In June 2016, the WVPSC issued an order that approved recovery of APCo and WPCo's total deferred billing, including carrying charges through June 2018, totaling $29 million. Recovery was approved over two years, effective July 2016. The WVPSC also approved implementation of the prospective $25 million base rate increase effective July 2016. See the "West Virginia Deferred Base Rate Increase" section of Note 4.

TCC and TNC Distribution Cost Recovery Factor (DCRF) Filings

In April 2016, TCC and TNC filed separate requests with the PUCT for approval of DCRF riders to allow recovery of eligible net distribution investments. TCC's and TNC's requests included revenue requirements of $54 million and $16 million, respectively, both to be effective September 2016. Amounts approved would be subject to refund based upon a prudence review of the investments in TCC's and TNC's next base rate cases. In June 2016, TCC and TNC, along with intervenors, filed separate settlement agreements with the PUCT that included proposed annual revenue requirements of $45 million and $11 million, respectively, both to be effective September 2016. In July 2016, the PUCT approved both settlement agreements.

TCC and TNC Merger

In June 2016, TCC and TNC filed applications with the PUCT and FERC that requested approval to merge TCC and TNC into AEP Utilities, Inc. Upon merger, AEP Utilities, Inc. will change its name to AEP Texas Inc. The proposed merger would be effective December 31, 2016. The applications proposed no changes to current TCC and TNC rates. A hearing at the PUCT is scheduled for August 2016.

Kingsport Base Rate Case

In January 2016, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66%. In June 2016, intervenor testimony was filed at the TRA. Intervenor testimony recommended a $7 million annual increase in base rates with an 8.8% return on common equity. A hearing at the TRA is scheduled for August 2016. If KGPCo does not recover its costs, it could reduce future net income and cash flows and impact financial condition.

Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo’s existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo’s next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017. APCo’s financial statements adequately address the impact of these amendments. The amendments provide that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In February 2016, APCo filed a motion to stay the Virginia SCC’s consideration of the petition due to a pending appeal at the Supreme Court of Virginia by industrial customers of a non-related utility regarding the constitutionality of the amendments. In May 2016, these industrial customers withdrew their appeal at the Supreme Court of Virginia. In July 2016, the Virginia SCC issued an order that denied the petition filed by the APCo industrial customers. Also in July 2016, these APCo industrial customers filed with the Virginia SCC a Notice of Appeal of the order to the Supreme Court of Virginia.

PJM Capacity Market

AGR is required to offer all of its available generation capacity in the PJM Reliability Pricing Model (RPM) auction, which is conducted three years in advance of the delivery year.

Through May 2015, AGR provided generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo paid AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo paid AGR its blended tariff rate for capacity consisting of $188.88/MW day for auctioned load and the non-fuel generation portion of its base rate for non-auctioned load. As of June 2015, AGR’s generation resources are compensated through the PJM capacity auction. Shown below are the RPM results through the June 2017 through May 2018 period:

PJM Auction Period	PJM Auction Price (per MW day)
June 2014 through May 2015	$125.99
June 2015 through May 2016	136.00
June 2016 through May 2017	59.37
June 2017 through May 2018	120.00

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In June 2015, FERC approved PJM's proposal to create a new Capacity Performance (CP) product, intended to improve generator performance and reliability during emergency events by allowing higher offers into the RPM auction and imposing greater charges for non-performance during emergency events. PJM procured approximately 80% CP and 20% Base Capacity for the June 2018 through May 2019 and June 2019 through May 2020 periods, while transitioning to 100% CP with the June 2020 through May 2021 period. FERC also approved transition incremental auctions to procure CP for the June 2016 through May 2017 and June 2017 through May 2018 periods.

In the third quarter of 2015, PJM conducted the two transition auctions. The transition auctions allowed generators, including AGR, to re-offer cleared capacity that qualifies as CP. Shown below are the results of the two transition auctions:

PJM Auction Period	Capacity Performance Transition Incremental Auction Price (per MW day)
June 2016 through May 2017	$134.00
June 2017 through May 2018	151.50

AGR cleared 7,169MW at $134/MW-day for the June 2016 through May 2017 period, replacing the original auction clearing price of $59.37/MW-day. AGR cleared 6,495MW for the June 2017 through May 2018 period at $151.50/MW-day, replacing the original auction clearing price of $120/MW-day.

In August 2015, PJM held its first base residual auction implementing CP rules for the June 2018 through May 2019 period. AGR cleared 7,209 MW at the CP auction price of $164.77/MW-day. The base residual auction for the June 2019 through May 2020 period was conducted in May 2016. AGR cleared 7,301 MW at the CP auction price of $100/MW-day. Shown below are the results for the June 2018 through May 2019 and June 2019 through May 2020 periods:

PJM Auction Period	Capacity Performance Auction Price (per MW day)	Base Capacity Auction Price (per MW day)
June 2018 through May 2019	$164.77	$150.00
June 2019 through May 2020	100.00	80.00

The FERC order exempted Fixed Resource Requirement (FRR) entities, including APCo, I&M, KPCo and WPCo, from the CP rules through the delivery period ending May 2019. Beginning in June 2019, FRR entities are subject to CP rules. In July 2015, AEP filed a request seeking rehearing of the FERC order approving CP. FERC denied AEP's request for rehearing in May 2016.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on the regulatory proceedings and pending litigation see Note 4 - Rate Matters, Note 6 - Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2015 Annual Report. Additionally, see Note 4 - Rate Matters and Note 5 - 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.

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Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiff's claims. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, Plaintiffs filed a notice of appeal and the matter is currently pending before the U.S. Court of Appeals for the Sixth Circuit. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP is implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. Additional investments and operational changes will need to be made in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM, CO_2 and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, rules governing the beneficial use and disposal of coal combustion products, clean water rules and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. AEP, along with various industry groups, affected states and other parties challenged some of the Federal EPA requirements in court. Management is also engaged in the development of possible future requirements including the items discussed below and state plans to reduce CO_2 emissions to address concerns about global climate change. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

See a complete discussion of these matters in the "Environmental Issues" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2015 Annual Report. AEP will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If AEP is unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of June 30, 2016, the AEP System had a total generating capacity of approximately 31,000 MWs, of which approximately 16,000 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP's investment to meet these proposed requirements ranges from approximately $3.2 billion to $3.8 billion through 2025. These amounts include investments to convert some of the coal generation to natural gas.

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 (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors. In addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and competitive plants.

In May 2015, the following plants or units of plants were retired:

Company	Plant Name and Unit	Generating Capacity (in MWs)
AGR	Kammer Plant	630
AGR	Muskingum River Plant	1,440
AGR	Picway Plant	100
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
KPCo	Big Sandy Plant, Unit 2	800
Total		5,535

As of June 30, 2016, the net book value of the AGR units listed above was zero. The net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the regulated plants in the table above was approved for recovery, except for $144 million which management plans to seek regulatory approval.

In April 2016, AEP retired the following units of plants:

Company	Plant Name and Unit	Generating Capacity (in MWs)
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		998

As of June 30, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the PSO and SWEPCo units listed above was $162 million. For Northeastern Station, Unit 4, PSO is seeking regulatory recovery of remaining net book values. For Welsh Plant, Unit 2, SWEPCo will seek regulatory recovery of remaining net book values.

In October 2015, KPCo obtained permits following the KPSC's approval to convert its 278 MW Big Sandy Plant, Unit 1 to natural gas. Big Sandy Plant, Unit 1 began operations as a natural gas unit in May 2016.

APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert its 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In the third and fourth quarters of 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the retired coal related assets for Clinch River Plant, Units 1 and 2, management plans to seek regulatory approval for $24 million. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively.

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 and impact financial condition.

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 the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA. All of the states in which AEP's power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012, but the rule was remanded to the Federal EPA upon further review and remains in effect. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" section below.

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) will 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 SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls currently under construction. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In July 2015, management submitted comments to the proposed Arkansas FIP and participated in comments filed by industry associations of which AEP is a member. Management supports compliance with CSAPR programs as satisfaction of the BART requirements.

The Federal EPA issued rules for CO_2 emissions that apply to new and existing electric utility units. See "Climate Change, CO_2 Regulation and Energy Policy" section below.

The Federal EPA also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 and ozone. In October 2015, the Federal EPA announced a lower final NAAQS for ozone of 70 parts per billion. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. A petition for review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In December 2015, the Federal EPA issued a proposal to revise the ozone season NO_x budgets in 23 states beginning in 2017 to address transport issues associated with the 2008 ozone standard and the budget errors identified in the U.S. Court of Appeals for the District of Columbia Circuit's July 2015 decision. The proposal was open for public comment through February 1, 2016. Management believes that the Federal EPA mistakenly relied on future projected retirements and failed to take into account actual operating experience when establishing the 2017 budgets. Management also believes there is insufficient time to implement the required reductions.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 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 units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). 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 was required within three years. Management obtained a one-year administrative extension at several units to facilitate 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.

In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule for further proceedings consistent with the U.S. Supreme Court's decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Management submitted comments on the proposal and will continue to monitor future regulatory developments. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. The rule remains in effect.

Climate Change, CO_2 Regulation and Energy Policy

The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. Management is taking steps to comply with these requirements, including increasing wind power purchases and broadening the AEP System's portfolio of energy efficiency programs.

In October 2015, the Federal EPA published the final standards for new, modified and reconstructed fossil fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources. The final standard for new combustion turbines is 1,000 pounds of CO_2 per MWh and the final standard for new fossil steam units is 1,400 pounds of CO_2 per MWh. Reconstructed turbines are subject to the same standard as new units and no standard for modified combustion turbines was issued. Reconstructed fossil steam units are subject to a standard of 1,800 pounds of CO_2 per MWh for larger units and 2,000 pounds of CO_2 per MWh for smaller units. Modified fossil steam units will be subject to a site specific standard no lower than the standards that would be applied if the units were reconstructed.

The final emissions guidelines for existing sources, known as the Clean Power Plan (CPP), are based on a series of declining emission rates that are implemented beginning in 2022 through 2029. The final emission rate is 771 pounds of CO_2 per MWh for existing natural gas combined cycle units and 1,305 pounds of CO_2 per MWh for existing fossil steam units in 2030 and thereafter. The Federal EPA also developed a set of rate-based and mass-based state goals.

The Federal EPA also published proposed "model" rules that can be adopted by the states that would allow sources within "trading ready" state programs to trade, bank or sell allowances or credits issued by the states. These rules would also be the basis for any federal plan issued by the Federal EPA in a state that fails to submit or receive approval for a state plan. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. The Federal EPA established a 90-day public comment period on the proposed rules and management submitted comments. In June 2016, the Federal EPA issued a separate proposal for the Clean Energy Incentive Program (CEIP) that was included in the model rules. The Federal EPA will accept comments on the proposed rules through August 29, 2016. Through the CEIP, states could issue allowances or credits for eligible actions prior to the first compliance period under the CPP. Management is evaluating the potential impacts of the final CPP and the proposed CEIP, as well as the anticipated actions by states where assets are located. The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could 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 AEP to close some coal-fired facilities and could lead to possible impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants.

The final rule became effective in October 2015. The Federal EPA will regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements. The rule does not apply to inactive CCR landfills and inactive surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice and internet posting requirements. The CCR rule requirements contain a compliance schedule spanning an approximate four year implementation period. If CCR units do not meet these standards within the timeframes provided, they will be required to close. Extensions of time for closure are available provided there is no alternative disposal capacity or the owner can certify cessation of a boiler by a certain date. Challenges to the rule by industry associations of which AEP is a member are proceeding. In April 2016, the parties entered into a settlement agreement that would require the Federal EPA to reconsider certain aspects of the rule. In June 2016, the U.S. Court of Appeals for the District of Columbia issued an order granting the voluntary remand of certain provisions including the Federal EPA’s issuance of a rule vacating the provision creating specific closure requirements for inactive surface impoundments that complete closure by April 17, 2018. The Federal EPA will propose a rule to extend the deadlines for these facilities to comply with the CCR standards promptly and attempt to finalize that rule within four months. The Federal EPA will also use its best efforts to complete reconsideration of all of the affected provisions within three years.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented. Management recorded a $95 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Management will continue to evaluate the rule’s impact on operations.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from AEP’s generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Encapsulated beneficial uses are not materially impacted by the new rule but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to 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 final rule affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In addition to other requirements, the final rule establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. The applicability of these requirements is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. Management will continue to review the final rule in detail to evaluate whether the plants are currently meeting the proposed limitations, what technologies are incorporated into AEP's long-range plans and what additional costs might be incurred. Management is assessing technology additions and retrofits.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This jurisdictional definition applies to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a "significant nexus." Management believes that clarity and efficiency in the permitting process is needed. Management remains concerned that the rule introduces new concepts and could subject more of AEP's operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. Challengers include industry associations of which AEP is a member. The U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule pending jurisdictional determinations. In February 2016, the U.S. Court of Appeals for the Sixth Circuit issued a decision holding that it has exclusive jurisdiction to decide the challenges to the "waters of the United States" rule. Industry, state and related associations, including an association in which AEP is a member, have filed petitions for a rehearing of the jurisdictional decision. In April 2016, the U.S. Court of Appeals for the Sixth Circuit denied the petitions and proceeded to issue a case management order for the merits of the case.

RESULTS OF OPERATIONS

SEGMENTS

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its 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.

AEP's reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

The remainder of AEP's activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other)" section of Note 6 for additional information.

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three and six months ended June 30, 2016 and 2015.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Vertically Integrated Utilities	$209.4	$206.9	$487.0	$506.2

Transmission and Distribution Utilities	124.6	77.6	232.6	174.8
AEP Transmission Holdco	94.6	65.2	138.5	101.0
Generation & Marketing	49.7	81.3	120.4	268.7
Corporate and Other	23.8	(1.0)	24.8	8.5
Earnings Attributable to AEP Common Shareholders	$502.1	$430.0	$1,003.3	$1,059.2

AEP CONSOLIDATED

Second Quarter of 2016 Compared to Second Quarter of 2015

Earnings Attributable to AEP Common Shareholders increased from $430 million in 2015 to $502 million in 2016 primarily due to:

- An increase in income at AEP Transmission Holdco as a result of increased transmission investment as well as an increase due to annual formula rate true-up adjustments.
- A decrease in system income taxes primarily due to the reversal of an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS resulting in a change in the valuation allowance.
- An increase due to increased revenues from Ohio transmission and distribution riders.

These increases were partially offset by:

- A decrease in generation revenues due to lower capacity revenue and a decrease in wholesale energy prices.
- A decrease due to the final accounting of the disposition of barging operations.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Earnings Attributable to AEP Common Shareholders decreased from $1.1 billion in 2015 to $1.0 billion in 2016 primarily due to:

- A decrease in generation revenues due to lower capacity revenue and a decrease in wholesale energy prices.
- A decrease in weather-related usage.

These decreases were partially offset by:

- A decrease in system income taxes primarily due to lower pretax book income and the reversal of an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS in the second quarter of 2016 resulting in a change in the valuation allowance.
- An increase in income at AEP Transmission Holdco as a result of increased transmission investment as well as an increase due to annual formula rate true-up adjustments.
- An increase in weather-normalized sales.

AEP's results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in millions)			
Revenues	$2,125.9	$2,182.5	$4,371.5	$4,687.6
Fuel and Purchased Electricity	699.5	780.6	1,441.5	1,763.8
Gross Margin	1,426.4	1,401.9	2,930.0	2,923.8
Other Operation and Maintenance	624.3	615.2	1,253.9	1,190.6
Depreciation and Amortization	271.0	266.2	537.8	538.4
Taxes Other Than Income Taxes	98.1	93.7	196.0	190.6
Operating Income	433.0	426.8	942.3	1,004.2
Interest and Investment Income	1.0	2.7	1.6	3.2
Carrying Costs Income	5.1	3.2	7.3	5.1
Allowance for Equity Funds Used During Construction	10.6	16.0	25.4	30.1
Interest Expense	(135.9)	(131.8)	(263.2)	(262.4)
Income Before Income Tax Expense and Equity Earnings	313.8	316.9	713.4	780.2
Income Tax Expense	104.5	110.1	226.4	273.7
Equity Earnings of Unconsolidated Subsidiaries	1.2	1.1	2.2	1.7
Net Income	210.5	207.9	489.2	508.2
Net Income Attributable to Noncontrolling Interests	1.1	1.0	2.2	2.0
Earnings Attributable to AEP Common Shareholders	$209.4	$206.9	$487.0	$506.2

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in millions of KWhs)			
Retail:				
Residential	6,674	6,672	15,798	17,051
Commercial	6,190	6,296	12,070	12,307
Industrial	8,654	8,937	16,921	17,297
Miscellaneous	565	574	1,106	1,122
Total Retail	22,083	22,479	45,895	47,777
Wholesale (a)	5,696	5,903	10,488	14,171
Total KWhs	27,779	28,382	56,383	61,948

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the 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 Vertically Integrated Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in degree days)			
Eastern Region				
Actual – Heating (a)	164	93	1,684	2,138
Normal – Heating (b)	137	139	1,770	1,743
Actual – Cooling (c)	347	402	352	402
Normal – Cooling (b)	327	324	332	329
Western Region				
Actual – Heating (a)	7	9	685	1,049
Normal – Heating (b)	34	34	926	911
Actual – Cooling (c)	713	704	743	718
Normal – Cooling (b)	693	693	716	716

(a) Heating degree days are calculated on a 55 degree temperature base.

(b) Normal Heating/Cooling represents the thirty-year average of degree days.

(c) Cooling degree days are calculated on a 65 degree temperature base.

Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Second Quarter of 2015	$206.9
Changes in Gross Margin:	
Retail Margins	46.8
Off-system Sales	(5.7)
Transmission Revenues	(16.2)
Other Revenues	(0.4)
Total Change in Gross Margin	24.5
Changes in Expenses and Other:	
Other Operation and Maintenance	(9.1)
Depreciation and Amortization	(4.8)
Taxes Other Than Income Taxes	(4.4)
Interest and Investment Income	(1.7)
Carrying Costs Income	1.9
Allowance for Equity Funds Used During Construction	(5.4)
Interest Expense	(4.1)
Total Change in Expenses and Other	(27.6)
Income Tax Expense	5.6
Equity Earnings	0.1
Net Income Attributable to Noncontrolling Interests	(0.1)
Second Quarter of 2016	$209.4

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

- Retail Margins increased $47 million primarily due to the following:
- The effect of rate proceedings in AEP’s service territories which included:
- A $58 million increase primarily due to increases in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016.
- A $15 million increase for PSO due to interim base rate increases.
- A $12 million increase for KPCo primarily due to increases in base rates and riders.
- A $9 million increase for I&M due to increases in riders in the Indiana service territory.
- A $7 million increase for SWEPCo due to revenue increases from rate riders in Arkansas and Texas.

For the increases described above, $48 million relate to riders/trackers which have corresponding increases in expense items below.
These increases were partially offset by:

- A $27 million decrease for SWEPCo in municipal and cooperative revenues primarily due to a true-up of formula rates in 2015.

- An $18 million decrease for I&M in FERC municipal and cooperative revenues due to annual formula rate adjustments.
- A $15 million decrease primarily due to lower weather-normalized margins in the eastern region.
- Margins from Off-system Sales decreased $6 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $16 million primarily due to lower Network Integration Transmission Service revenues, partially offset by an increase in SPP margins.

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

- Other Operation and Maintenance expenses increased $9 million primarily due to the following:
- A $12 million increase in SPP and PJM transmission services expense.
- A $10 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
- A $9 million increase in recoverable expenses primarily including vegetation management and storm expenses fully recovered in rate recovery riders/trackers.
- A $4 million increase in storm expenses, primarily in the APCo region.

These increases were partially offset by:

- A $21 million decrease in plant outages, primarily due to the timing of planned outages in the eastern region.
- A $6 million decrease due to a gain on the sale of property in the current year in the APCo region.
- Depreciation and Amortization expenses increased $5 million primarily related to interim rate increases in Oklahoma partially offset by a decrease in amortization related to an advanced metering rider in Oklahoma.
- Taxes Other Than Income Taxes increased $4 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction decreased $5 million primarily due to the completion of environmental projects at SWEPCo.
- Interest Expense increased $4 million primarily due to increased long-term debt balances in I&M.
- Income Tax Expense decreased $6 million primarily due to other book/tax differences which are accounted for on a flow-through basis.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015
Reconciliation of Six Months Ended June 30, 2015 to Six Months
Ended June 30, 2016
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Six Months Ended June 30, 2015	$506.2
Changes in Gross Margin:	
Retail Margins	55.7
Off-system Sales	(23.2)
Transmission Revenues	(27.7)
Other Revenues	1.4
Total Change in Gross Margin	6.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(63.3)
Depreciation and Amortization	0.6
Taxes Other Than Income Taxes	(5.4)
Interest and Investment Income	(1.6)
Carrying Costs Income	2.2
Allowance for Equity Funds Used During Construction	(4.7)
Interest Expense	(0.8)
Total Change in Expenses and Other	(73.0)
Income Tax Expense	47.3
Equity Earnings	0.5
Net Income Attributable to Noncontrolling Interests	(0.2)
Six Months Ended June 30, 2016	$487.0

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

- Retail Margins increased $56 million primarily due to the following:
- The effect of rate proceedings in AEP's service territories which include:
- An $85 million increase primarily due to increases in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016. This increase is partially offset by a prior year adjustment affected by the amended Virginia law that has an impact on biennial reviews.
- A $29 million increase for KPCo primarily due to increases in base rates and riders.
- A $19 million increase for PSO due to interim base rate increases.
- An $11 million increase for I&M due to increases in riders in the Indiana service territory.
- A $9 million increase for SWEPCo due to revenue increases from rate riders in Arkansas and Texas.

For the increases described above, $85 million relate to riders/trackers which have corresponding increases in expense items below.

- A $13 million increase in weather-normalized margins in the eastern region.

These increases were partially offset by:

- An $82 million decrease in weather-related usage.
- A $25 million decrease for SWEPCo in municipal and cooperative revenues primarily due to a true-up of formula rates in 2015.
- A $13 million decrease for I&M in FERC municipal and cooperative revenues due to annual formula rate adjustments.

- Margins from Off-system Sales decreased $23 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $28 million primarily due to lower Network Integration Transmission Service revenues, partially offset by an increase in SPP margins.

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

- Other Operation and Maintenance expenses increased $63 million primarily due to the following:
- A $24 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
- A $21 million increase in recoverable expenses, primarily including vegetation management, storm and PJM expenses fully recovered in rate recovery riders/trackers.
- A $15 million increase in employee-related expenses.
- A $13 million increase in SPP and PJM transmission services expense.
- A $6 million increase due to the reduction of an environmental liability in 2015 at I&M.
- A $6 million increase in storm expenses, primarily in the APCo region.

These increases were partially offset by:

- A $21 million decrease in plant outages, primarily due to the timing of planned outages in the eastern region.
- A $6 million decrease due to a gain on the sale of property in the current year in the APCo region.
- Taxes Other Than Income Taxes increased $5 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction decreased $5 million primarily due to transmission projects being placed in service in 2016.
- Income Tax Expense decreased $47 million primarily due to a decrease in pretax book income, other book/tax differences which are accounted for on a flow-through basis and by the recording of state and federal income tax adjustments.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in millions)			
Revenues	$1,096.1	$1,060.7	$2,192.9	$2,330.8
Purchased Electricity	191.0	270.5	408.6	691.3
Amortization of Generation Deferrals	51.8	35.4	106.9	66.8
Gross Margin	853.3	754.8	1,677.4	1,572.7
Other Operation and Maintenance	325.9	288.3	650.3	607.6
Depreciation and Amortization	167.3	170.4	323.6	338.1
Taxes Other Than Income Taxes	117.7	117.7	241.0	239.9
Operating Income	242.4	178.4	462.5	387.1
Interest and Investment Income	1.1	1.4	3.3	3.3
Carrying Costs Income	1.2	5.1	3.1	11.6
Allowance for Equity Funds Used During Construction	4.1	4.0	8.4	7.7
Interest Expense	(65.4)	(68.0)	(132.6)	(137.6)
Income Before Income Tax Expense	183.4	120.9	344.7	272.1
Income Tax Expense	58.8	43.3	112.1	97.3
Net Income	124.6	77.6	232.6	174.8
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$124.6	$77.6	$232.6	$174.8

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in millions of KWhs)			
Retail:				
Residential	6,009	5,630	12,250	12,896
Commercial	6,602	6,372	12,389	12,287
Industrial	5,506	5,809	11,004	11,089
Miscellaneous	175	177	341	338
Total Retail (a)	18,292	17,988	35,984	36,610
Wholesale (b)	412	429	735	963
Total KWhs	18,704	18,417	36,719	37,573

(a) Represents energy delivered to distribution customers.
(b) Primarily Ohio’s contractually obligated purchases of OVEC power sold into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the 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 Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in degree days)			
Eastern Region				
Actual – Heating (a)	238	137	1,929	2,575
Normal – Heating (b)	184	186	2,103	2,067
Actual – Cooling (c)	308	350	309	350
Normal – Cooling (b)	289	287	292	290
Western Region				
Actual – Heating (a)	2	—	123	320
Normal – Heating (b)	4	4	198	192
Actual – Cooling (d)	926	863	1,085	904
Normal – Cooling (b)	917	917	1,026	1,026

(a) 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 70 degree temperature base.

Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Second Quarter of 2015	$77.6
Changes in Gross Margin:	
Retail Margins	126.5
Off-system Sales	(6.9)
Transmission Revenues	(2.5)
Other Revenues	(18.6)
Total Change in Gross Margin	98.5
Changes in Expenses and Other:	
Other Operation and Maintenance	(37.6)
Depreciation and Amortization	3.1
Interest and Investment Income	(0.3)
Carrying Costs Income	(3.9)
Allowance for Equity Funds Used During Construction	0.1
Interest Expense	2.6
Total Change in Expenses and Other	(36.0)
Income Tax Expense	(15.5)
Second Quarter of 2016	$124.6

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins increased $127 million primarily due to the following:
- A $57 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $21 million increase due to a reversal of a regulatory provision resulting from a favorable court decision in Ohio.
- A $10 million increase in Ohio riders such as Universal Service Fund (USF) and gridSMART®. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
- An $8 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.
- A $7 million increase in Texas weather-normalized margins primarily in the residential class.
- A $6 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
- A $4 million increase in carrying charges primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- Margins from Off-system Sales decreased $7 million primarily due to losses from a power contract with OVEC.
- Transmission Revenues decreased $3 million primarily due to the following:
- A $23 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015,

partially offset by a corresponding increase in Retail Margins above.

This decrease was partially offset by:

- A $12 million increase in Ohio due to a settlement recorded in 2015, a decrease in amortization of the formula rate true-up and the recording of the current year formula rate true-up in 2016.
- An $8 million increase primarily due to increased transmission investment in ERCOT.

- Other Revenues decreased $19 million primarily due to the following:
  - A $14 million decrease due to a decrease in Texas securitization revenue offset in Depreciation and Amortization and other expense items below.
  - A $5 million decrease due to decreased pole attachment revenue in Ohio due to a prior period favorable adjustment.

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

- Other Operation and Maintenance expenses increased $38 million primarily due to the following:
  - A $40 million increase in recoverable expenses, primarily including PJM expenses and gridSMART® expenses, currently fully recovered in rate recovery riders/trackers.
  - A $5 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
  - A $2 million decrease in vegetation management expenses.
  - A $2 million decrease in storm expenses, primarily in the Texas region.
- Depreciation and Amortization expenses decreased $3 million primarily due to the following:
  - A $9 million decrease in TCC's securitization transition asset due to the final maturity of the first Texas securitization bond, which is partially offset in Other Revenues.

  This decrease was partially offset by:
  - A $4 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Carrying Costs Income decreased $4 million due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
- Income Tax Expense increased $16 million primarily due to an increase in pretax book income partially offset by the recording of state income tax adjustments.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015
Reconciliation of Six Months Ended June 30, 2015 to Six Months
Ended June 30, 2016
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Six Months Ended June 30, 2015	$174.8
Changes in Gross Margin:	
Retail Margins	181.4
Off-system Sales	(17.8)
Transmission Revenues	(23.2)
Other Revenues	(35.7)
Total Change in Gross Margin	104.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(42.7)
Depreciation and Amortization	14.5
Taxes Other Than Income Taxes	(1.1)
Carrying Costs Income	(8.5)
Allowance for Equity Funds Used During Construction	0.7
Interest Expense	5.0
Total Change in Expenses and Other	(32.1)
Income Tax Expense	(14.8)
Six Months Ended June 30, 2016	$232.6

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins increased $181 million primarily due to the following:
  - A $118 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
  - A $21 million increase due to a reversal of a regulatory provision resulting from a favorable court decision in Ohio.
  - A $15 million increase in Texas weather-normalized margins primarily in the residential class.
  - A $14 million increase in Ohio riders such as Universal Service Fund (USF) and gridSMART®. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
  - A $12 million increase in revenues associated with the Ohio DIR.
  - A $9 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  - A $16 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
  - An $8 million decrease in weather-related usage in Texas.
- Margins from Off-system Sales decreased $18 million primarily due to losses from a power contract with OVEC.

- Transmission Revenues decreased $23 million primarily due to the following:
  - A $54 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

This decrease was partially offset by:

- An $18 million increase primarily due to increased transmission investment in ERCOT.
- A $12 million increase in Ohio due to a settlement recorded in 2015, a decrease in amortization of the formula rate true-up and the recording of the current year formula rate true-up in 2016.
- Other Revenues decreased $36 million primarily due to a decrease in Texas securitization revenue offset in Depreciation and Amortization and other expense items below.

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

- Other Operation and Maintenance expenses increased $43 million primarily due to the following:
- A $66 million increase in recoverable expenses, primarily including PJM expenses and gridSMART® expenses, currently fully recovered in rate recovery riders/trackers.
- A $6 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

These increases were partially offset by:

- A $15 million decrease due to the completion of the Ohio amortization of 2012 deferred storm expenses. This decrease was offset by a corresponding increase in Retail Margins above.
- A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- A $5 million decrease in vegetation management expenses.
- Depreciation and Amortization expenses decreased $15 million primarily due to the following:
- A $24 million decrease in TCC’s securitization transition asset due to the final maturity of the first Texas securitization bond, which is partially offset in Other Revenues.
- A $6 million decrease in recoverable gridSMART® depreciation expenses.

These decreases were partially offset by:

- A $7 million increase due to recoveries of Ohio transmission cost rider carrying costs. This increase was offset by a corresponding increase in Retail Margins above.
- A $6 million increase in amortization expenses for the collection of carrying costs on Ohio deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- Carrying Costs Income decreased $9 million due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
- Interest Expense decreased $5 million primarily due to a decrease in TCC’s securitization transition assets. This decrease was offset by a corresponding decrease in Other Revenues above.
- Income Tax Expense increased $15 million primarily due to an increase in pretax book income partially offset by the recording of state and federal income tax adjustments.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	(in millions)			
Transmission Revenues	$161.7	$99.5	$250.3	$157.4
Other Operation and Maintenance	8.8	8.0	20.5	15.8
Depreciation and Amortization	15.8	9.5	31.3	18.6
Taxes Other Than Income Taxes	21.8	16.6	43.0	32.8
Operating Income	115.3	65.4	155.5	90.2
Interest and Investment Income	0.2	—	0.2	0.1
Carrying Costs Expense	(0.2)	(0.1)	(0.2)	(0.1)
Allowance for Equity Funds Used During Construction	13.9	14.1	26.3	26.0
Interest Expense	(11.6)	(8.6)	(23.4)	(17.2)
Income Before Income Tax Expense and Equity Earnings	117.6	70.8	158.4	99.0
Income Tax Expense	47.6	29.1	68.0	42.8
Equity Earnings of Unconsolidated Subsidiaries	25.3	23.8	49.6	45.6
Net Income	95.3	65.5	140.0	101.8
Net Income Attributable to Noncontrolling Interests	0.7	0.3	1.5	0.8
Earnings Attributable to AEP Common Shareholders	$94.6	$65.2	$138.5	$101.0

Summary of Net Plant in Service and CWIP for AEP Transmission Holdco

	June 30, 2016	June 30, 2015
	(in millions)	
Net Plant in Service	$3,068.4	$2,111.2
CWIP	1,385.6	1,129.5

Second Quarter of 2016 Compared to Second Quarter of 2015

Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Second Quarter of 2015	$65.2
Changes in Transmission Revenues:	
Transmission Revenues	62.2
Total Change in Transmission Revenues	62.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(0.8)
Depreciation and Amortization	(6.3)
Taxes Other Than Income Taxes	(5.2)
Interest and Investment Income	0.2
Carrying Costs Expense	(0.1)
Allowance for Equity Funds Used During Construction	(0.2)
Interest Expense	(3.0)
Total Change in Expenses and Other	(15.4)
Income Tax Expense	(18.5)
Equity Earnings	1.5
Net Income Attributable to Noncontrolling Interests	(0.4)
Second Quarter of 2016	$94.6

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates, were as follows:

- Transmission Revenues increased $62 million primarily due to the following:
- A $33 million increase in projects placed in-service by AEP’s wholly-owned transmission subsidiaries.
- A $29 million increase due to annual formula rate true-up adjustments.

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

- Depreciation and Amortization expenses increased $6 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased property taxes as a result of additional transmission investment.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Reconciliation of Six Months Ended June 30, 2015 to Six Months Ended June 30, 2016
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Six Months Ended June 30, 2015	$101.0
Changes in Transmission Revenues:	
Transmission Revenues	92.9
Total Change in Transmission Revenues	92.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(4.7)
Depreciation and Amortization	(12.7)
Taxes Other Than Income Taxes	(10.2)
Interest and Investment Income	0.1
Carrying Costs Expense	(0.1)
Allowance for Equity Funds Used During Construction	0.3
Interest Expense	(6.2)
Total Change in Expenses and Other	(33.5)
Income Tax Expense	(25.2)
Equity Earnings	4.0
Net Income Attributable to Noncontrolling Interests	(0.7)
Six Months Ended June 30, 2016	$138.5

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates, were as follows:

- Transmission Revenues increased $93 million primarily due to the following:
  - A $64 million increase in projects placed in-service by AEP’s wholly-owned transmission subsidiaries.
  - A $29 million increase due to annual formula rate true-up adjustments.

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

- Other Operation and Maintenance expenses increased $5 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $13 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $10 million primarily due to increased property taxes as a result of additional transmission investment.
- Interest Expense increased $6 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $25 million primarily due to an increase in pretax book income.
- Equity Earnings increased $4 million primarily due to increased transmission investment by ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in millions)			
Revenues	$683.8	$800.2	$1,431.8	$1,970.7
Fuel, Purchased Electricity and Other	443.7	490.9	923.2	1,206.9
Gross Margin	240.1	309.3	508.6	763.8
Other Operation and Maintenance	100.8	116.4	194.4	216.4
Depreciation and Amortization	50.6	50.8	99.3	100.9
Taxes Other Than Income Taxes	10.4	10.8	20.3	19.9
Operating Income	78.3	131.3	194.6	426.6
Interest and Investment Income	—	0.6	0.5	1.6
Allowance for Equity Funds Used During Construction	0.2	—	0.4	—
Interest Expense	(8.6)	(10.1)	(17.6)	(20.6)
Income Before Income Tax Expense	69.9	121.8	177.9	407.6
Income Tax Expense	20.2	40.5	57.5	138.9
Net Income	49.7	81.3	120.4	268.7
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$49.7	$81.3	$120.4	$268.7

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in millions of MWhs)			
Fuel Type:				
Coal	6	6	11	16
Natural Gas	3	3	7	7
Total MWhs	9	9	18	23

Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Second Quarter of 2015	$81.3
Changes in Gross Margin:	
Generation	(76.3)
Retail, Trading and Marketing	9.1
Other	(2.0)
Total Change in Gross Margin	(69.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	15.6
Depreciation and Amortization	0.2
Taxes Other Than Income Taxes	0.4
Interest and Investment Income	(0.6)
Allowance for Equity Funds Used During Construction	0.2
Interest Expense	1.5
Total Change in Expenses and Other	17.3
Income Tax Expense	20.3
Second Quarter of 2016	$49.7

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, purchased electricity and certain cost of service for retail operations were as follows:

- Generation decreased $76 million primarily due to lower capacity revenues due to plant retirements and the transition of the Ohio Standard Service offer to full market pricing and a decrease in wholesale energy prices partially offset by favorable hedging activity.
- Retail, Trading and Marketing increased $9 million primarily due to the impact of favorable wholesale trading and marketing performance in the second quarter of 2016 partially offset by lower retail margins.

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

- Other Operation and Maintenance expenses decreased $16 million primarily due to plant retirements in June 2015.
- Income Tax Expense decreased $20 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Reconciliation of Six Months Ended June 30, 2015 to Six Months
Ended June 30, 2016
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

Six Months Ended June 30, 2015	$268.7
Changes in Gross Margin:	
Generation	(224.8)
Retail, Trading and Marketing	(28.0)
Other	(2.4)
Total Change in Gross Margin	(255.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	22.0
Depreciation and Amortization	1.6
Taxes Other Than Income Taxes	(0.4)
Interest and Investment Income	(1.1)
Allowance for Equity Funds Used During Construction	0.4
Interest Expense	3.0
Total Change in Expenses and Other	25.5
Income Tax Expense	81.4
Six Months Ended June 30, 2016	$120.4

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, purchased electricity and certain cost of service for retail operations were as follows:

- Generation decreased $225 million primarily due to lower capacity revenues due to plant retirements and the transition of the Ohio Standard Service offer to full market pricing and a decrease in wholesale energy prices partially offset by favorable hedging activity.
- Retail, Trading and Marketing decreased $28 million when compared to the impact of favorable wholesale trading and marketing performance in the first quarter of 2015.

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

- Other Operation and Maintenance expenses decreased $22 million primarily due to plant retirements in June 2015.
- Income Tax Expense decreased $81 million primarily due to a decrease in pretax book income.

CORPORATE AND OTHER

Second Quarter of 2016 Compared to Second Quarter of 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $1 million in 2015 to a gain of $24 million in 2016 primarily due to the reversal of an unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS partially offset by charges related to the final accounting of the disposition of AEP's commercial barging operations.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from income of $9 million in 2015 to income of $25 million in 2016 primarily due to the reversal of an unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS partially offset by charges related to the final accounting of the disposition of AEP's commercial barging operations and decreased income from the discontinued operations of AEP's commercial barging operations which was sold in November 2015.

AEP SYSTEM INCOME TAXES

Second Quarter of 2016 Compared to Second Quarter of 2015

Income Tax Expense decreased $59 million primarily due to the reversal of an unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS and by the recording of state income tax adjustments, partially offset by an increase in pretax book income.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Income Tax Expense decreased $151 million primarily due to a decrease in pretax book income, the reversal of an unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS in the second quarter of 2016 and by the recording of other state and federal income tax adjustments.

FINANCIAL CONDITION

AEP measures financial condition by the strength of its balance sheet and the liquidity provided by its cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	June 30, 2016		December 31, 2015	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$19,543.7	48.9 %	$19,572.7	51.1 %
Short-term Debt	2,060.3	5.1	800.0	2.1
Total Debt	21,604.0	54.0	20,372.7	53.2
AEP Common Equity	18,386.2	46.0	17,891.7	46.8
Noncontrolling Interests	18.7	—	13.2	—
Total Debt and Equity Capitalization	$40,008.9	100.0%	$38,277.6	100.0%

AEP’s ratio of debt-to-total capital increased from 53.2% as of December 31, 2015 to 54.0% as of June 30, 2016 primarily due to an increase in short-term debt.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of June 30, 2016, AEP had $3.5 billion in aggregate credit facility commitments to support its operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses 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.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of June 30, 2016, available liquidity was approximately $2.3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 3,000.0	June 2021
Revolving Credit Facility	500.0	June 2018
Total	3,500.0	
Cash and Cash Equivalents	246.8	
Total Liquidity Sources	3,746.8	
Less: AEP Commercial Paper Outstanding	1,409.3	
Net Available Liquidity	$ 2,337.5	

AEP has two credit facilities totaling $3.5 billion to support its commercial paper program. The $3 billion credit facility allows management to issue letters of credit in an amount up to $1.2 billion.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first six months of 2016 was $1.5 billion. The weighted-average interest rate for AEP's commercial paper during 2016 was 0.75%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit under three uncommitted facilities totaling $225 million. As of June 30, 2016, the maximum future payment for letters of credit issued under the uncommitted facilities was $150 million with maturities ranging from July 2016 to June 2017.

Securitized Accounts Receivable

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2018.

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Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a 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 AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of June 30, 2016, this contractually-defined percentage was 51.5%. Nonperformance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's 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. This condition also applies in a majority of AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its 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 and AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.56 per share in July 2016. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

Management does not believe these restrictions related to AEP's various financing arrangements and regulatory requirements will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

AEP does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but its access to the commercial paper market may depend on their credit ratings. In addition, downgrades in AEP's credit ratings by one of the rating agencies could increase its borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject AEP to additional collateral demands under adequate assurance clauses under its derivative and non-derivative energy contracts.

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders.

	Six Months Ended June 30,	
	2016	2015
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$176.4	$162.5
Net Cash Flows from Continuing Operating Activities	1,725.8	2,198.9
Net Cash Flows Used for Continuing Investing Activities	(2,299.7)	(2,194.5)
Net Cash Flows from Continuing Financing Activities	646.8	27.9
Net Cash Flows from (Used for) Discontinued Operations	(2.5)	0.4
Net Increase in Cash and Cash Equivalents	70.4	32.7
Cash and Cash Equivalents at End of Period	$246.8	$195.2

AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

Operating Activities

	Six Months Ended June 30,	
	2016	2015
	(in millions)	
Income from Continuing Operations	$1,009.5	$1,051.6
Depreciation and Amortization	1,010.9	993.1
Deferred Income Taxes	552.3	450.2
Fuel, Materials and Supplies	(107.0)	148.0
Accrued Taxes, Net	(303.7)	(112.1)
Other	(436.2)	(331.9)
Net Cash Flows from Continuing Operating Activities	$1,725.8	$2,198.9

Net Cash Flows from Continuing Operating Activities were $1.7 billion in 2016 consisting primarily of Net Income of $1 billion and $1 billion of noncash Depreciation and Amortization. A significant change in other items includes the unfavorable effects of an increase in fuel inventory due to the mild winter weather in addition to a decrease in Accrued Taxes primarily due to the impacts of bonus depreciation related to the Protecting Americans from Tax Hikes Act of 2015. Deferred Income Taxes increased primarily due to an increase in tax versus book temporary differences from operations, which includes provisions related to the Protecting Americans from Tax Hikes Act of 2015. 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.

Net Cash Flows from Continuing Operating Activities were $2.2 billion in 2015 consisting primarily of Net Income of $1.1 billion and $1 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2014 and an increase in tax versus book temporary differences from operations. The reduction in Fuel, Materials and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather, increased generation and plants retired during the second quarter of 2015.

Investing Activities

	Six Months Ended June 30, 2016	2015
	(in millions)	
Construction Expenditures	$(2,285.8)	$(2,181.5)
Acquisitions of Nuclear Fuel	(79.2)	(52.2)
Other	65.3	39.2
Net Cash Flows Used for Continuing Investing Activities	$(2,299.7)	$(2,194.5)

Net Cash Flows Used for Continuing Investing Activities were $2.3 billion in 2016 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Continuing Investing Activities were $2.2 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Six Months Ended June 30, 2016	2015
	(in millions)	
Issuance of Common Stock, Net	$30.9	$55.8
Issuance of Debt, Net	1,219.6	636.6
Dividends Paid on Common Stock	(553.1)	(522.1)
Other	(50.6)	(142.4)
Net Cash Flows Used for Continuing Financing Activities	$646.8	$27.9

Net Cash Flows Used for Continuing Financing Activities in 2016 were $647 million. AEP's net debt issuances were $1.2 billion. The net issuances included an increase in short-term borrowing of $1.3 billion, issuances of $400 million of senior unsecured notes, $125 million of pollution control bonds and $218 million of other debt notes offset by retirements of $354 million of senior unsecured notes, $189 million of securitization bonds, $185 million of pollution control bonds and $56 million of other debt notes. AEP paid common stock dividends of $553 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Continuing Financing Activities in 2015 were $28 million. AEP's net debt issuances were $637 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $140 million of pollution control bonds and $729 million of other debt notes offset by retirements of $754 million of senior unsecured and other debt notes, $180 million of securitization bonds, $140 million of pollution control bonds and $653 of other debt notes and a decrease in short term borrowing of $241 million. AEP paid common stock dividends of $522 million. Other includes a make whole premium payment on the extinguishment of long-term debt of $93 million in addition to capital lease principal payments of $50 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In July 2016, PSO issued $50 million of 3.05% Senior Unsecured Notes due in 2026 and $100 million of 4.11% Senior Unsecured Notes due in 2046.

In July 2016, I&M retired $9 million of Notes Payable related to DCC Fuel.

In July 2016, OPCo retired $23 million of Securitization Bonds.

In July 2016, TCC retired $65 million of Securitization Bonds.

In July 2016, TCC retired its variable rate $100 million Other Long-term Debt due in 2016 and issued $125 million of variable rate Other Long-term Debt due in 2019.

In July 2016, TNC retired its variable rate $75 million Other Long-term Debt due in 2016 and issued $75 million of variable rate Other Long-term Debt due in 2019.

OFF-BALANCE SHEET ARRANGEMENTS

AEP's current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that AEP enters in the normal course of business. The following identifies significant off-balance sheet arrangements:

	June 30, 2016	December 31, 2015
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$960.1	$ 1,034.0
Railcars Maximum Potential Loss from Lease Agreement	18.1	18.1

For complete information on each of these off-balance sheet arrangements, see the "Off-balance Sheet Arrangements" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2015 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2015 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 Discussion and Analysis of Financial Condition and Results of Operations" in the 2015 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2016

The FASB issued ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" eliminating the concept of extraordinary items for presentation on the face of the statements of income. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements. Management adopted ASU 2015-01 effective January 1, 2016.

The FASB issued ASU 2015-05 "Customer's Accounting for Fees paid in a Cloud Computing Arrangement" providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management adopted ASU 2015-05 prospectively, effective January 1, 2016, with no impact on results of operations, financial position or cash flows.

Pronouncements Effective in the Future

The FASB issued ASU 2014-09 “Revenue from Contracts with Customers” clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for annual periods beginning after December 15, 2016. Management is analyzing the impact of this new standard and the related ASUs that clarify guidance in the standard. At this time, management cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

The FASB issued ASU 2015-11 “Simplifying the Measurement of Inventory” to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management does not expect the new standard to impact the Registrants’ results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

The FASB issued ASU 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for sale securities in combination with the entity’s other deferred tax assets. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

The FASB issued ASU 2016-02 “Accounting for Leases” increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard. The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact the Registrants’ financial position, but not the Registrants’ results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

The FASB issued ASU 2016-09 “Compensation – Stock Compensation” simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income. The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management plans to adopt ASU 2016-09 effective January 1, 2017.

The FASB issued ASU 2016-13 “Measurement of Credit Losses on Financial Instruments” requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including hedge accounting, consolidations and pension and postretirement benefits. 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

The Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. In addition, this segment is exposed to foreign currency exchange risk from occasionally procuring various services and materials used in its energy business from foreign suppliers. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates.

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a major power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the

Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of

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Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2015:
MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2016

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets as of December 31, 2015	$8.6	$ 14.4	$ 143.2	$166.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(12.2)	2.6	(4.9)	(14.5)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	24.1	24.1
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	(0.1)	8.2	8.1
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(9.6)	(31.8)	—	(41.4)
Total MTM Risk Management Contract Net Assets as of June 30, 2016	$(13.2)	$ (14.9)	$ 170.6	142.5
Commodity Cash Flow Hedge Contracts				3.0
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(0.2)
Fair Value Hedge Contracts				1.1
Collateral Deposits				10.7
Total MTM Derivative Contract Net Assets as of June 30, 2016				$157.1

(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 losses of those contracts that are not reflected on the statements of income. These net losses are recorded as regulatory assets.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is limited in 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. Management uses 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.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of June 30, 2016, credit exposure net of collateral to sub investment grade counterparties was approximately 7.2%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of June 30, 2016, the following table approximates AEP’s 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	$714.2	$ 3.1	$ 711.1	3	$ 346.7
Split Rating	19.4	—	19.4	1	19.2
No External Ratings:					
Internal Investment Grade	95.9	—	95.9	2	50.5
Internal Noninvestment Grade	79.1	14.7	64.4	3	42.0
Total as of June 30, 2016	$908.6	$ 17.8	$ 890.8	9	$ 458.4
Total as of December 31, 2015	$973.6	$ 21.9	$ 951.7	11	$ 437.1

In addition, AEP is exposed to credit risk related to participation in RTOs. For each of the RTOs in which AEP participates, this risk is generally determined based on the proportionate share of member gross activity over a specified period of time.

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP’s commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of June 30, 2016, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities. The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio
Six Months Ended Twelve Months Ended

June 30, 2016				December 31, 2015			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.4	$1.1	$ 0.2	$0.1	$0.2	$0.9	$ 0.2	$0.1

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VaR Model
Non-Trading Portfolio

Six Months Ended				Twelve Months Ended			
June 30, 2016				December 31, 2015			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$2.2	$2.8	$ 0.9	$0.4	$1.1	$2.4	$ 0.9	$0.4

Management back-tests 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 the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of June 30, 2016 and December 31, 2015, the estimated EaR on AEP's debt portfolio for the following twelve months was $33 million and $25 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES				
Vertically Integrated Utilities	$2,108.2	$ 2,158.6	$4,326.3	$ 4,646.0
Transmission and Distribution Utilities	1,076.2	1,008.0	2,153.5	2,214.3
Generation & Marketing	655.3	627.6	1,369.2	1,486.8
Other Revenues	53.2	32.5	88.8	60.0
TOTAL REVENUES	3,892.9	3,826.7	7,937.8	8,407.1
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	680.4	755.3	1,356.0	1,826.5
Purchased Electricity for Resale	629.2	600.8	1,360.6	1,319.2
Other Operation	664.5	603.4	1,379.6	1,264.7
Maintenance	289.4	326.0	568.1	611.6
Depreciation and Amortization	513.8	497.7	1,010.9	993.1
Taxes Other Than Income Taxes	249.4	239.4	503.5	485.1
TOTAL EXPENSES	3,026.7	3,022.6	6,178.7	6,500.2
OPERATING INCOME	866.2	804.1	1,759.1	1,906.9
Other Income (Expense):				
Interest and Investment Income	2.4	3.1	4.5	4.5
Carrying Costs Income	6.3	8.2	10.2	16.6
Allowance for Equity Funds Used During Construction	28.8	34.1	60.5	63.8
Interest Expense	(224.9)	(219.2)	(441.9)	(437.9)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	678.8	630.3	1,392.4	1,553.9
Income Tax Expense	165.0	224.3	400.5	551.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(7.4)	25.4	17.6	49.2
INCOME FROM CONTINUING OPERATIONS	506.4	431.4	1,009.5	1,051.6
INCOME (LOSS) FROM DISCONTINUED OPERATIONS, NET OF TAX	(2.5)	(0.1)	(2.5)	10.4
NET INCOME	503.9	431.3	1,007.0	1,062.0
Net Income Attributable to Noncontrolling Interests	1.8	1.3	3.7	2.8
	$502.1	$ 430.0	$1,003.3	$ 1,059.2

EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	491,459,544	490,207,482	491,283,964	489,904,417
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 1.03	$ 0.88	$ 2.05	$ 2.14
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	$ (0.01)	$ —	$ (0.01)	$ 0.02
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.02	$ 0.88	$ 2.04	$ 2.16
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	491,641,400	490,484,450	491,486,854	490,212,271
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 1.03	$ 0.88	$ 2.05	$ 2.14
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	$ (0.01)	$ —	$ (0.01)	$ 0.02
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.02	$ 0.88	$ 2.04	$ 2.16
CASH DIVIDENDS DECLARED PER SHARE	$ 0.56	$ 0.53	$ 1.12	$ 1.06

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Net Income	$503.9	$431.3	$1,007.0	$1,062.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $8.2 and $0.5 for the Three Months Ended June 30, 2016 and 2015, Respectively, and $4.2 and $(2.9) for the Six Months Ended June 30, 2016 and 2015, Respectively	15.2	1.0	7.8	(5.4)
Securities Available for Sale, Net of Tax of $0.4 and $(0.1) for the Three Months Ended June 30, 2016 and 2015, Respectively, and $0.7 and $0.2 for the Six Months Ended June 30, 2016 and 2015, Respectively	0.6	(0.2)	1.2	0.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0.1 for the Three Months Ended June 30, 2016 and 2015, Respectively, and $0.1 and $0.3 for the Six Months Ended June 30, 2016 and 2015, Respectively	0.1	0.2	0.2	0.6
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	15.9	1.0	9.2	(4.5)
TOTAL COMPREHENSIVE INCOME	519.8	432.3	1,016.2	1,057.5
Total Comprehensive Income Attributable to Noncontrolling Interests	1.8	1.3	3.7	2.8
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$518.0	$431.0	$1,012.5	$1,054.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2016 and 2015
(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, 2014	509.7	$3,313.3	$6,203.4	$7,406.6	$ (103.1)	$ 4.3	$16,824.5
Issuance of Common Stock	1.2	7.4	48.4				55.8
Common Stock Dividends				(520.0)		(2.1)	(522.1)
Other Changes in Equity			1.6			2.6	4.2
Deferred State Income Tax Rate Adjustment			16.8				16.8
Net Income				1,059.2		2.8	1,062.0
Other Comprehensive Loss					(4.5)		(4.5)
Pension and OPEB Adjustment Related to Mitchell Plant					5.1		5.1
TOTAL EQUITY - JUNE 30, 2015	510.9	$3,320.7	$6,270.2	$7,945.8	$ (102.5)	$ 7.6	$17,441.8
TOTAL EQUITY - DECEMBER 31, 2015	511.4	$3,324.0	$6,296.5	$8,398.3	$ (127.1)	$ 13.2	$17,904.9
Issuance of Common Stock	0.6	4.0	26.9				30.9
Common Stock Dividends				(550.8)		(2.3)	(553.1)
Other Changes in Equity			1.3	0.6		4.1	6.0
Net Income				1,003.3		3.7	1,007.0
Other Comprehensive Income					9.2		9.2
TOTAL EQUITY - JUNE 30, 2016	512.0	$3,328.0	$6,324.7	$8,851.4	$ (117.9)	$ 18.7	$18,404.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$246.8	$ 176.4
Other Temporary Investments (June 30, 2016 and December 31, 2015 Amounts Include $293.5 and $376.6, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	306.9	386.8
Accounts Receivable:		
Customers	692.4	615.9
Accrued Unbilled Revenues	99.0	31.2
Pledged Accounts Receivable – AEP Credit	989.0	940.3
Miscellaneous	71.7	82.1
Allowance for Uncollectible Accounts	(36.9)	(29.0)
Total Accounts Receivable	1,815.2	1,640.5
Fuel	716.4	600.8
Materials and Supplies	645.6	738.6
Risk Management Assets	111.1	134.4
Accrued Tax Benefits	272.7	58.9
Regulatory Asset for Under-Recovered Fuel Costs	106.5	115.2
Margin Deposits	72.5	107.3
Prepayments and Other Current Assets	145.2	113.5
TOTAL CURRENT ASSETS	4,438.9	4,072.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,746.2	25,559.8
Transmission	14,878.6	14,247.9
Distribution	18,431.1	18,046.9
Other Property, Plant and Equipment (June 30, 2016 and December 31, 2015 Amounts Include Coal Mining and Nuclear Fuel, December 31, 2015 Amount Includes 2016 Plant Retirements)	3,516.6	3,722.9
Construction Work in Progress	3,509.9	3,903.9
Total Property, Plant and Equipment	67,082.4	65,481.4
Accumulated Depreciation and Amortization	19,646.2	19,348.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	47,436.2	46,133.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,259.1	5,140.3
Securitized Assets	1,631.9	1,749.9
Spent Nuclear Fuel and Decommissioning Trusts	2,196.0	2,106.4
Goodwill	52.5	52.5
Long-term Risk Management Assets	298.5	321.8

Deferred Charges and Other Noncurrent Assets	2,004.0	2,106.6
TOTAL OTHER NONCURRENT ASSETS	11,442.0	11,477.5
TOTAL ASSETS	$63,317.1	$ 61,683.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT LIABILITIES		
Accounts Payable	$ 1,242.3	$ 1,418.0
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	651.0	675.0
Other Short-term Debt	1,409.3	125.0
Total Short-term Debt	2,060.3	800.0
Long-term Debt Due Within One Year (June 30, 2016 and December 31, 2015 Amounts Include $383.9 and $410.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,006.3	1,831.8
Risk Management Liabilities	85.7	87.1
Customer Deposits	335.8	346.6
Accrued Taxes	814.0	979.1
Accrued Interest	227.0	226.9
Regulatory Liability for Over-Recovered Fuel Costs	59.9	113.9
Other Current Liabilities	1,038.6	1,305.1
TOTAL CURRENT LIABILITIES	7,869.9	7,108.5
NONCURRENT LIABILITIES		
Long-term Debt (June 30, 2016 and December 31, 2015 Amounts Include $1,855.9 and $1,971.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	17,537.4	17,740.9
Long-term Risk Management Liabilities	166.8	179.1
Deferred Income Taxes	12,402.5	11,733.2
Regulatory Liabilities and Deferred Investment Tax Credits	3,816.0	3,736.1
Asset Retirement Obligations	1,851.9	1,806.5
Employee Benefits and Pension Obligations	496.6	583.3
Deferred Credits and Other Noncurrent Liabilities	771.1	890.6
TOTAL NONCURRENT LIABILITIES	37,042.3	36,669.7
TOTAL LIABILITIES	44,912.2	43,778.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2016	2015

Shares Authorized	600,000,000	600,000,000		
Shares Issued	511,999,477	511,389,173		
(20,336,592 Shares were Held in Treasury as of June 30, 2016 and December 31, 2015)			3,328.0	3,324.0
Paid-in Capital			6,324.7	6,296.5
Retained Earnings			8,851.4	8,398.3
Accumulated Other Comprehensive Income (Loss)			(117.9)	(127.1)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			18,386.2	17,891.7
Noncontrolling Interests			18.7	13.2
TOTAL EQUITY			18,404.9	17,904.9
TOTAL LIABILITIES AND EQUITY			$63,317.1	$ 61,683.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Six Months Ended June 30,	
	2016	2015
OPERATING ACTIVITIES		
Net Income	$1,007.0	$1,062.0
Income (Loss) from Discontinued Operations	(2.5)	10.4
Income from Continuing Operations	1,009.5	1,051.6
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:		
Depreciation and Amortization	1,010.9	993.1
Deferred Income Taxes	552.3	450.2
Carrying Costs Income	(10.2)	(16.6)
Allowance for Equity Funds Used During Construction	(60.5)	(63.8)
Mark-to-Market of Risk Management Contracts	48.7	(41.1)
Amortization of Nuclear Fuel	73.2	65.5
Pension Contributions to Qualified Plan Trust	(84.8)	(92.5)
Property Taxes	131.3	102.0
Deferred Fuel Over/Under-Recovery, Net	(5.8)	21.5
Deferral of Ohio Capacity Costs, Net	67.4	(1.1)
Change in Other Noncurrent Assets	(191.0)	(78.8)
Change in Other Noncurrent Liabilities	1.8	17.5
Changes in Certain Components of Continuing Working Capital:		
Accounts Receivable, Net	(166.0)	(34.0)
Fuel, Materials and Supplies	(107.0)	148.0
Accounts Payable	(22.6)	(13.2)
Accrued Taxes, Net	(303.7)	(112.1)
Other Current Assets	26.3	20.2
Other Current Liabilities	(244.0)	(217.5)
Net Cash Flows from Continuing Operating Activities	1,725.8	2,198.9
INVESTING ACTIVITIES		
Construction Expenditures	(2,285.8)	(2,181.5)
Change in Other Temporary Investments, Net	80.9	30.7
Purchases of Investment Securities	(1,797.4)	(541.5)
Sales of Investment Securities	1,777.0	515.8
Acquisitions of Nuclear Fuel	(79.2)	(52.2)
Other Investing Activities	4.8	34.2
Net Cash Flows Used for Continuing Investing Activities	(2,299.7)	(2,194.5)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	30.9	55.8
Issuance of Long-term Debt	743.4	2,603.3
Change in Short-term Debt, Net	1,260.3	(241.0)
Retirement of Long-term Debt	(784.1)	(1,725.7)

Make Whole Premium on Extinguishment of Long-term Debt	—	(92.7)
Principal Payments for Capital Lease Obligations	(51.0)	(49.8)
Dividends Paid on Common Stock	(553.1)	(522.1)
Other Financing Activities	0.4	0.1
Net Cash Flows from Continuing Financing Activities	646.8	27.9
Net Cash Flows from (Used for) Discontinued Operating Activities	(2.5)	4.6
Net Cash Flows from Discontinued Investing Activities	—	4.1
Net Cash Flows Used for Discontinued Financing Activities	—	(8.3)
Net Increase in Cash and Cash Equivalents	70.4	32.7
Cash and Cash Equivalents at Beginning of Period	176.4	162.5
Cash and Cash Equivalents at End of Period	$246.8	$195.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$425.4	$430.6
Net Cash Paid for Income Taxes	26.2	97.7
Noncash Acquisitions Under Capital Leases	52.7	75.8
Construction Expenditures Included in Current Liabilities as of June 30,	554.2	543.0
Construction Expenditures Included in Noncurrent Liabilities as of June 30,	—	66.3
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	41.5	—

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	2,134	2,238	5,898	6,440
Commercial	1,606	1,690	3,302	3,417
Industrial	2,363	2,567	4,631	5,027
Miscellaneous	203	212	420	428
Total Retail	6,306	6,707	14,251	15,312
Wholesale	928	788	1,384	1,654
Total KWhs	7,234	7,495	15,635	16,966

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	108	55	1,433	1,735
Normal - Heating (b)	91	91	1,435	1,412
Actual - Cooling (c)	380	471	388	471
Normal - Cooling (b)	363	360	369	366

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Net Income
(in millions)

Second Quarter of 2015	$59.0
Changes in Gross Margin:	
Retail Margins	33.1
Off-system Sales	(0.2)
Transmission Revenues	(8.5)
Other Revenues	(0.5)
Total Change in Gross Margin	23.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.7)
Depreciation and Amortization	(0.1)
Taxes Other Than Income Taxes	(0.5)
Interest Income	(0.3)
Carrying Costs Income	0.6
Allowance for Equity Funds Used During Construction	(1.6)
Interest Expense	1.4
Total Change in Expenses and Other	(11.2)
Income Tax Expense	1.7
Second Quarter of 2016	$73.4

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

- Retail Margins increased $33 million primarily due to the following:
  - A $55 million increase primarily due to increases in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016. Of these rate increases, $28 million relates to riders/trackers which have corresponding increases in other expense items below.

  This increase was partially offset by:
  - A $19 million decrease in weather-normalized margin primarily due to lower industrial sales.
- Transmission Revenues decreased $9 million primarily due to lower Network Integrated Transmission Service (NITS) revenues.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $11 million primarily due to the following:
- A $10 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
- A $5 million increase in storm related expenses.
- A $4 million increase in uncollectible accounts expense due to a prior year establishment of a regulatory asset for recovery as approved in the May 2015 West Virginia base case order. This increase in expense is partially offset within Retail Margins above.
- A $2 million increase in amortization of previously deferred West Virginia storm expenses as approved in the May 2015 West Virginia base case order. This increase in expense is offset within Retail Margins above.
- A $2 million increase in transmission and distribution expenses primarily due to vegetation management. This increase in expense is offset within Retail Margins above.

These increases were partially offset by:

- A $6 million gain on the sale of property in the current year.
- A $5 million decrease in plant maintenance expenses related to prior year outages at certain plants.
- A $2 million decrease in PJM transmission expenses.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015
Reconciliation of Six Months Ended June 30, 2015 to Six Months
Ended June 30, 2016
Net Income
(in millions)

Six Months Ended June 30, 2015	$200.8
Changes in Gross Margin:	
Retail Margins	38.5
Off-system Sales	(1.6)
Transmission Revenues	(16.7)
Other Revenues	1.7
Total Change in Gross Margin	21.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(42.2)
Depreciation and Amortization	4.6
Taxes Other Than Income Taxes	(0.8)
Interest Income	(0.4)
Carrying Costs Income	(0.5)
Allowance for Equity Funds Used During Construction	(2.3)
Interest Expense	4.7
Total Change in Expenses and Other	(36.9)
Income Tax Expense	13.9
Six Months Ended June 30, 2016	$199.7

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

- Retail Margins increased $39 million primarily due to the following:
- A $77 million increase primarily due to increases in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016. This increase is partially offset by a prior year adjustment affected by the amended Virginia law that has an impact on biennial reviews. Of these rate increases, $55 million relate to riders/trackers which have corresponding increases in other expense items below.
- A $5 million decrease in generation-related PJM expenses mainly driven by lower PJM ancillaries and transmission losses and higher FTR revenues, all net of recovery.

The overall increase was partially offset by:

- A $35 million decrease in weather-related usage due to an 18% decrease in cooling degree days and a 17% decrease in heating degree days.
- A $12 million decrease in weather-normalized margin primarily in the industrial class, offset by the residential and commercial classes.
- Transmission Revenues decreased $17 million primarily due to lower NITS revenues.

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

- Other Operation and Maintenance expenses increased $42 million primarily due to the following:
  - A $24 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $9 million increase in transmission and distribution expenses primarily due to vegetation management. This increase in expense is offset within Retail Margins above.
  - An $8 million increase in storm related expenses.
  - A $5 million increase in amortization of previously deferred West Virginia storm expenses as approved in the May 2015 West Virginia base case order. This increase in expense is offset within Retail Margins above.
  - A $4 million increase in employee-related expenses.
  - A $4 million increase in uncollectible accounts expense due to a prior year establishment of a regulatory asset for recovery as approved in the May 2015 West Virginia base case order. This increase in expense is partially offset within Retail Margins above.
  - A $3 million increase in customer assistance expense due to the energy efficiency programs implemented in 2016. This increase in expense is offset within Retail Margins above.

  These increases were partially offset by:
  - A $7 million decrease in PJM transmission expenses.
  - A $6 million gain on the sale of property in the current year.
  - A $3 million decrease in plant maintenance expenses related to prior year outages at certain plants.
- Depreciation and Amortization expenses decreased $5 million primarily due to the following:
  - A $6 million decrease in asset retirement obligations and plant amortizations due to plant retirements in 2015.
  - A $2 million decrease due to prior year amortization of Virginia environmental deferrals. This decrease in expense is offset within Retail Margins above.

  These decreases were partially offset by:
  - A $3 million increase due to a higher depreciable base.
- Interest Expense decreased $5 million primarily due to lower interest rates on long-term debt.
- Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income, other book/tax differences which are accounted for on a flow-through basis and the regulatory accounting treatment of state income taxes.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$638.8	$645.4	$1,414.3	$1,499.6
Sales to AEP Affiliates	32.2	33.9	72.6	76.4
Other Revenues	2.5	2.7	6.6	5.0
TOTAL REVENUES	673.5	682.0	1,493.5	1,581.0
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	153.3	183.5	304.0	406.8
Purchased Electricity for Resale	63.5	65.7	171.7	178.4
Other Operation	111.2	103.7	231.8	209.8
Maintenance	60.2	57.0	129.5	109.3
Depreciation and Amortization	96.4	96.3	191.9	196.4
Taxes Other Than Income Taxes	30.6	30.1	61.9	61.1
TOTAL EXPENSES	515.2	536.3	1,090.8	1,161.8
OPERATING INCOME	158.3	145.7	402.7	419.2
Other Income (Expense):				
Interest Income	0.2	0.5	0.5	0.9
Carrying Costs Income	1.0	0.4	0.2	0.7
Allowance for Equity Funds Used During Construction	2.3	3.9	4.6	6.9
Interest Expense	(47.3)	(48.7)	(94.3)	(99.0)
INCOME BEFORE INCOME TAX EXPENSE	114.5	101.8	313.7	328.7
Income Tax Expense	41.1	42.8	114.0	127.9
NET INCOME	$73.4	$59.0	$199.7	$200.8

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

See Condensed Notes to Condensed

Financial
Statements of
Registrants
beginning on
page 109.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net Income	$73.4	$59.0	$199.7	$200.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $0 for the Three Months Ended June 30, 2016 and 2015, Respectively, and $(0.2) and $0.1 for the Six Months Ended June 30, 2016 and 2015, Respectively	(0.2)	—	(0.4)	0.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.3) for the Three Months Ended June 30, 2016 and 2015, Respectively, and $(0.4) and $(0.5) for the Six Months Ended June 30, 2016 and 2015, Respectively	(0.4)	(0.5)	(0.7)	(0.9)
TOTAL OTHER COMPREHENSIVE LOSS	(0.6)	(0.5)	(1.1)	(0.8)
TOTAL COMPREHENSIVE INCOME	$72.8	$58.5	$198.6	$200.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 260.4	$ 1,809.6	$ 1,291.9	$ 5.0	$ 3,366.9
Common Stock Dividends			(118.8)		(118.8)
Net Income			200.8		200.8
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$ 260.4	$ 1,809.6	$ 1,373.9	$ 4.2	$ 3,448.1
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 260.4	$ 1,828.7	$ 1,388.7	$ (2.8)	$ 3,475.0
Common Stock Dividends			(150.0)		(150.0)
Net Income			199.7		199.7
Other Comprehensive Loss				(1.1)	(1.1)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2016	$ 260.4	$ 1,828.7	$ 1,438.4	$ (3.9)	$ 3,523.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$5.4	$ 2.8
Restricted Cash for Securitized Funding	15.0	14.8
Advances to Affiliates	24.6	25.6
Accounts Receivable:		
Customers	116.1	120.9
Affiliated Companies	58.1	51.2
Accrued Unbilled Revenues	33.2	17.9
Miscellaneous	1.6	2.2
Allowance for Uncollectible Accounts	(4.4)	(4.3)
Total Accounts Receivable	204.6	187.9
Fuel	154.0	119.3
Materials and Supplies	101.2	127.0
Risk Management Assets – Nonaffiliated	5.2	14.7
Risk Management Assets – Affiliated	—	0.9
Accrued Tax Benefits	14.6	30.6
Regulatory Asset for Under-Recovered Fuel Costs	86.8	86.9
Prepayments and Other Current Assets	13.8	17.4
TOTAL CURRENT ASSETS	625.2	627.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,312.9	6,200.8
Transmission	2,476.6	2,408.1
Distribution	3,474.4	3,402.5
Other Property, Plant and Equipment	362.6	345.5
Construction Work in Progress	479.5	475.1
Total Property, Plant and Equipment	13,106.0	12,832.0
Accumulated Depreciation and Amortization	3,527.6	3,407.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,578.4	9,424.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,143.7	1,154.2
Securitized Assets	316.6	328.0
Long-term Risk Management Assets – Nonaffiliated	0.2	0.1
Deferred Charges and Other Noncurrent Assets	126.0	113.7
TOTAL OTHER NONCURRENT ASSETS	1,586.5	1,596.0
TOTAL ASSETS	$11,790.1	$ 11,648.3

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 109.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2016 and December 31, 2015
(Unaudited)

	June 30, 2016	December 31, 2015
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$145.9	$ 181.0
Accounts Payable:		
General	161.4	196.5
Affiliated Companies	70.1	67.7
Long-term Debt Due Within One Year – Nonaffiliated	568.3	318.0
Risk Management Liabilities – Nonaffiliated	18.5	4.8
Customer Deposits	83.1	83.9
Accrued Taxes	72.2	79.5
Accrued Interest	40.7	40.6
Other Current Liabilities	144.1	153.4
TOTAL CURRENT LIABILITIES	1,304.3	1,125.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,476.2	3,612.7
Long-term Risk Management Liabilities – Nonaffiliated	0.3	0.1
Deferred Income Taxes	2,595.1	2,527.0
Regulatory Liabilities and Deferred Investment Tax Credits	626.8	637.1
Asset Retirement Obligations	100.6	98.9
Employee Benefits and Pension Obligations	103.3	114.4
Deferred Credits and Other Noncurrent Liabilities	59.9	57.7
TOTAL NONCURRENT LIABILITIES	6,962.2	7,047.9
TOTAL LIABILITIES	8,266.5	8,173.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	1,438.4	1,388.7
Accumulated Other Comprehensive Income (Loss)	(3.9)	(2.8)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,523.6	3,475.0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$11,790.1	$ 11,648.3

See
Condensed
Notes to

Condensed Financial Statements of Registrants beginning on page 109.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Six Months Ended June 30, 2016		2015	
OPERATING ACTIVITIES				
Net Income	$ 199.7		$ 200.8	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	191.9		196.4	
Deferred Income Taxes	68.3		122.5	
Carrying Costs Income	(0.2	)	(0.7	)
Allowance for Equity Funds Used During Construction	(4.6	)	(6.9	)
Mark-to-Market of Risk Management Contracts	24.2		(15.7	)
Pension Contributions to Qualified Plan Trust	(8.8	)	(10.0	)
Deferred Fuel Over/Under-Recovery, Net	3.8		(15.3	)
Change in Other Noncurrent Assets	(8.2	)	(2.0	)
Change in Other Noncurrent Liabilities	(16.3	)	(10.2	)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	(16.7	)	18.9	
Fuel, Materials and Supplies	(31.7	)	15.5	
Accounts Payable	(13.5	)	(20.6	)
Accrued Taxes, Net	7.8		(11.4	)
Other Current Assets	3.5		(2.2	)
Other Current Liabilities	(9.5	)	(21.0	)
Net Cash Flows from Operating Activities	389.7		438.1	
INVESTING ACTIVITIES				
Construction Expenditures	(322.3	)	(293.1	)
Change in Advances to Affiliates, Net	1.0		24.8	
Other Investing Activities	9.5		7.0	
Net Cash Flows Used for Investing Activities	(311.8	)	(261.3	)
FINANCING ACTIVITIES				

Issuance of Long-term Debt – Nonaffiliated	249.2	726.3
Change in Advances from Affiliates, Net	(35.1)	57.4
Retirement of Long-term Debt – Nonaffiliated	(136.5)	(661.0)
Retirement of Long-term Debt – Affiliated	—	(86.0)
Make Whole Premium on Extinguishment of Long-term Debt – Nonaffiliated	—	(92.7)
Principal Payments for Capital Lease Obligations	(3.1)	(2.5)
Dividends Paid on Common Stock	(150.0)	(118.8)
Other Financing Activities	0.2	0.4
Net Cash Flows Used for Financing Activities	(75.3)	(176.9)
Net Increase (Decrease) in Cash and Cash Equivalents	2.6	(0.1)
Cash and Cash Equivalents at Beginning of Period	2.8	2.6
Cash and Cash Equivalents at End of Period	$ 5.4	$ 2.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 90.9	$ 105.6
Net Cash Paid for Income Taxes	28.3	5.2
Noncash Acquisitions Under Capital Leases	0.8	1.9
Construction Expenditures Included in Current Liabilities as of June 30,	69.1	81.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

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INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	1,163	1,125	2,725	2,870
Commercial	1,193	1,193	2,375	2,402
Industrial	1,992	1,946	3,880	3,740
Miscellaneous	15	15	35	35
Total Retail	4,363	4,279	9,015	9,047
Wholesale	2,495	2,677	4,425	6,083
Total KWhs	6,858	6,956	13,440	15,130

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	279	172	2,196	2,931
Normal - Heating (b)	231	232	2,439	2,403
Actual - Cooling (c)	270	266	270	266
Normal - Cooling (b)	262	260	264	262

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to
Second Quarter of 2016
Net Income
(in millions)

Second Quarter of 2015	$50.6
Changes in Gross Margin:	
Retail Margins	1.8
Off-system Sales	(4.3)
Transmission Revenues	(5.2)
Other Revenues	(3.2)
Total Change in Gross Margin	(10.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	15.4
Depreciation and Amortization	2.5
Taxes Other Than Income Taxes	(3.6)
Other Income	2.2
Interest Expense	(4.1)
Total Change in Expenses and Other	12.4
Income Tax Expense	(0.8)
Second Quarter of 2016	$51.3

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

- Retail Margins increased $2 million primarily due to the following:
- A $9 million increase from rate proceedings in the Indiana service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
- A $5 million increase due to higher fuel cost recovery from retail customers.
- A $5 million increase in weather-normalized margins.
- A $3 million increase in weather-related usage due to a 62% increase in heating degree days.

These increases were partially offset by:
- An $18 million decrease in FERC municipal and cooperative revenues due to annual formula rate adjustments.
- Margins from Off-system Sales decreased $4 million due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $5 million primarily due to lower transmission formula rate true-up than in the prior year.
- Other Revenues decreased $3 million primarily due to a decrease in barging deliveries to the Rockport Plant by River Transportation Division (RTD). The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging below.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $15 million primarily due to the following:
- A $13 million decrease in nuclear expenses primarily due to $7 million related to Cook Plant, Unit 1 diesel generator repairs and $6 million for low pressure turbine inspections in 2015.
- A $3 million decrease in expenses due to the retirement of the Tanners Creek Plant in May 2015.
- A $3 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a corresponding decrease in Other Revenues from barging activities discussed above.

These decreases were partially offset by:

- A $2 million increase in transmission expenses primarily due to increased PJM expenses.
- A $2 million increase in distribution expenses primarily due to increased forestry and storm expenses.
- A $2 million increase in accretion due to the impact of a revision in the nuclear Asset Retirement Obligation (ARO) estimate on decommissioning expenses. This increase has a corresponding offset in Depreciation and Amortization expenses below.
- Depreciation and Amortization expenses decreased $3 million primarily due to the retirement of Tanners Creek Plant in May 2015 and a revision in the nuclear ARO estimate, partially offset by higher depreciable base. The decrease in nuclear ARO has a corresponding offset in Other Operation and Maintenance expenses above.
- Taxes Other Than Income Taxes increased $4 million primarily due to property taxes.
- Interest Expense increased $4 million primarily due to higher long-term debt balances.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Reconciliation of Six Months Ended June 30,
2015 to Six Months Ended June 30, 2016
Net Income
(in millions)

Six Months Ended June 30, 2015	$ 123.3
Changes in Gross Margin:	
Retail Margins	1.3
Off-system Sales	(9.3)
Transmission Revenues	(7.9)
Other Revenues	(2.0)
Total Change in Gross Margin	(17.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	9.5
Depreciation and Amortization	6.8
Taxes Other Than Income Taxes	(3.6)
Other Income	1.9
Interest Expense	(3.8)
Total Change in Expenses and Other	10.8
Income Tax Expense	9.8
Six Months Ended June 30, 2016	$ 126.0

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

- Retail Margins increased $1 million primarily due to the following:
  - A $13 million increase in weather-normalized margins.
  - A $12 million increase from rate proceedings in the Indiana service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
  - A $3 million decrease in PJM charges not currently recovered in rate recovery riders/trackers.
  - A $2 million increase due to higher fuel cost recovery from retail customers.

  These increases were partially offset by:
  - A $16 million decrease in weather-related usage due to a 25% decrease in heating degree days.
  - A $13 million decrease in FERC municipal and cooperative revenues due to annual formula rate adjustments offset by increased formula rate changes.
- Margins from Off-system Sales decreased $9 million due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $8 million primarily due to lower transmission formula rate true-up than in the prior year.
- Other Revenues decreased $2 million primarily due to a decrease in barging deliveries to the Rockport Plant by RTD. The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging below.

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

- Other Operation and Maintenance expenses decreased $10 million primarily due to the following:
- A $16 million decrease in nuclear expenses primarily due to $7 million related to Cook Plant, Unit 1 diesel generator repairs and $6 million for low pressure turbine inspections in 2015.
- A $7 million decrease due to the retirement of Tanners Creek Plant in May 2015.
- A $5 million decrease due to Rockport environmental compliance work performed in 2015.
- A $2 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a corresponding decrease in Other Revenues from barging activities above.

These decreases were partially offset by:

- A $6 million increase due to the reduction of an environmental liability in 2015.
- A $5 million increase in transmission expenses primarily due to increased PJM expenses.
- A $4 million increase in general and administrative expenses.
- A $4 million increase in accretion due to the impact of a revision in the nuclear ARO estimate on decommissioning expense. This increase has a corresponding offset in Depreciation and Amortization expenses below.
- Depreciation and Amortization expenses decreased $7 million primarily due to the retirement of Tanners Creek Plant in May 2015 and a revision in the nuclear ARO estimate, partially offset by higher depreciable base. The decrease in nuclear ARO has a corresponding offset in Other Operation and Maintenance expenses above.
- Taxes Other Than Income Taxes increased $4 million primarily due to property taxes.
- Interest Expense increased $4 million primarily due to higher long-term debt balances.
- Income Tax Expense decreased $10 million primarily due to the recording of federal income tax adjustments and a decrease in pretax book income.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$495.7	$515.1	$996.1	$1,081.3
Sales to AEP Affiliates	7.0	6.5	18.5	7.0
Other Revenues – Affiliated	15.4	21.9	30.7	40.5
Other Revenues – Nonaffiliated	4.3	0.8	9.8	1.8
TOTAL REVENUES	522.4	544.3	1,055.1	1,130.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	76.3	74.0	145.5	173.9
Purchased Electricity for Resale	41.0	50.3	90.6	106.2
Purchased Electricity from AEP Affiliates	56.0	60.0	101.4	115.0
Other Operation	133.7	137.3	275.0	266.3
Maintenance	48.0	59.8	88.9	107.1
Depreciation and Amortization	47.0	49.5	94.1	100.9
Taxes Other Than Income Taxes	25.6	22.0	49.0	45.4
TOTAL EXPENSES	427.6	452.9	844.5	914.8
OPERATING INCOME	94.8	91.4	210.6	215.8
Other Income (Expense):				
Interest Income	4.2	3.5	7.4	5.3
Allowance for Equity Funds Used During Construction	4.5	3.0	6.8	7.0
Interest Expense	(27.1)	(23.0)	(49.6)	(45.8)
INCOME BEFORE INCOME TAX EXPENSE	76.4	74.9	175.2	182.3
Income Tax Expense	25.1	24.3	49.2	59.0
NET INCOME	$51.3	$50.6	$126.0	$123.3

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Net Income	$51.3	$50.6	$126.0	$123.3
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.2 and $0.1 for the Three Months Ended June 30, 2016 and 2015, Respectively, and $0.4 and $0.3 for the Six Months Ended June 30, 2016 and 2015, Respectively	0.3	0.2	0.7	0.5
TOTAL COMPREHENSIVE INCOME	$51.6	$50.8	$126.7	$123.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 56.6	$ 980.9	$ 930.8	$ (14.3)	$ 1,954.0
Common Stock Dividends			(60.0)		(60.0)
Net Income			123.3		123.3
Other Comprehensive Income				0.5	0.5
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$ 56.6	$ 980.9	$ 994.1	$ (13.8)	$ 2,017.8
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 56.6	$ 980.9	$ 1,015.6	$ (16.7)	$ 2,036.4
Common Stock Dividends			(62.5)		(62.5)
Net Income			126.0		126.0
Other Comprehensive Income				0.7	0.7
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2016	$ 56.6	$ 980.9	$ 1,079.1	$ (16.0)	$ 2,100.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$2.5	$ 1.1
Advances to Affiliates	12.4	11.7
Accounts Receivable:		
Customers	57.6	43.9
Affiliated Companies	57.9	68.7
Accrued Unbilled Revenues	3.6	0.1
Miscellaneous	0.8	2.6
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	119.9	115.2
Fuel	64.4	46.5
Materials and Supplies	158.0	185.9
Risk Management Assets – Nonaffiliated	5.0	10.6
Risk Management Assets – Affiliated	0.1	1.7
Accrued Tax Benefits	45.8	40.5
Prepayments and Other Current Assets	48.3	42.1
TOTAL CURRENT ASSETS	456.4	455.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,956.0	3,841.7
Transmission	1,426.3	1,406.9
Distribution	1,839.9	1,790.8
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	691.0	662.3
Construction Work in Progress	564.1	519.8
Total Property, Plant and Equipment	8,477.3	8,221.5
Accumulated Depreciation, Depletion and Amortization	3,065.9	3,018.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,411.4	5,203.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	836.9	804.3
Spent Nuclear Fuel and Decommissioning Trusts	2,196.0	2,106.4
Long-term Risk Management Assets – Nonaffiliated	0.2	—
Deferred Charges and Other Noncurrent Assets	148.0	140.9
TOTAL OTHER NONCURRENT ASSETS	3,181.1	3,051.6
TOTAL ASSETS	$9,048.9	$ 8,710.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT LIABILITIES		
Advances from Affiliates	$11.4	$ 294.3
Accounts Payable:		
General	174.9	201.0
Affiliated Companies	63.5	61.8
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2016 and December 31, 2015 Amounts Include $95.9 and $84.6, Respectively, Related to DCC Fuel)	174.2	162.9
Risk Management Liabilities – Nonaffiliated	3.6	6.3
Customer Deposits	34.3	35.7
Accrued Taxes	70.9	74.2
Accrued Interest	32.3	26.2
Obligations Under Capital Leases	16.6	32.8
Other Current Liabilities	119.1	142.1
TOTAL CURRENT LIABILITIES	700.8	1,037.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,256.1	1,837.1
Long-term Risk Management Liabilities – Nonaffiliated	0.4	1.6
Deferred Income Taxes	1,471.9	1,361.5
Regulatory Liabilities and Deferred Investment Tax Credits	1,130.8	1,076.2
Asset Retirement Obligations	1,277.1	1,240.9
Deferred Credits and Other Noncurrent Liabilities	111.2	119.4
TOTAL NONCURRENT LIABILITIES	6,247.5	5,636.7
TOTAL LIABILITIES	6,948.3	6,674.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,079.1	1,015.6
Accumulated Other Comprehensive Income (Loss)	(16.0)	(16.7)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,100.6	2,036.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,048.9	$ 8,710.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Six Months Ended June 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$ 126.0	$ 123.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	94.1	100.9
Deferred Income Taxes	86.8	48.0
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(20.6)	(11.6)
Allowance for Equity Funds Used During Construction	(6.8)	(7.0)
Mark-to-Market of Risk Management Contracts	3.1	6.0
Amortization of Nuclear Fuel	73.2	65.5
Pension Contribution to Qualified Plan Trust	(12.7)	(14.6)
Deferred Fuel Over/Under-Recovery, Net	4.9	(15.1)
Change in Other Noncurrent Assets	(1.9)	31.0
Change in Other Noncurrent Liabilities	17.9	(9.8)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(6.0)	(2.3)
Fuel, Materials and Supplies	(19.3)	31.1
Accounts Payable	(26.8)	6.8
Accrued Taxes, Net	(9.2)	(7.8)
Other Current Assets	8.0	5.2
Other Current Liabilities	(19.7)	(37.1)
Net Cash Flows from Operating Activities	291.0	312.5
INVESTING ACTIVITIES		
Construction Expenditures	(258.9)	(221.6)
Change in Advances to Affiliates, Net	(0.7)	—
Purchases of Investment Securities	(1,796.4)	(540.7)

Sales of Investment Securities	1,777.0	515.8
Acquisitions of Nuclear Fuel	(79.2)	(52.2)
Other Investing Activities	4.0	7.4
Net Cash Flows Used for Investing Activities	(354.2)	(291.3)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	482.7	210.7
Change in Advances from Affiliates, Net	(282.9)	(1.8)
Retirement of Long-term Debt – Nonaffiliated	(53.5)	(150.1)
Principal Payments for Capital Lease Obligations	(19.8)	(20.2)
Dividends Paid on Common Stock	(62.5)	(60.0)
Other Financing Activities	0.6	0.5
Net Cash Flows from (Used for) Financing Activities	64.6	(20.9)
Net Increase in Cash and Cash Equivalents	1.4	0.3
Cash and Cash Equivalents at Beginning of Period	1.1	1.0
Cash and Cash Equivalents at End of Period	$ 2.5	$ 1.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 40.3	$ 42.3
Net Cash Paid (Received) for Income Taxes	(23.6)	17.1
Noncash Acquisitions Under Capital Leases	16.5	1.4
Construction Expenditures Included in Current Liabilities as of June 30,	89.8	53.1
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	41.5	—
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.1	0.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

OHIO POWER COMPANY AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	2,986	2,970	6,829	7,461
Commercial	3,633	3,550	7,044	7,145
Industrial	3,566	3,826	7,061	7,370
Miscellaneous	29	28	62	60
Total Retail (a)	10,214	10,374	20,996	22,036
Wholesale (b)	412	429	735	963
Total KWhs	10,626	10,803	21,731	22,999

(a) Represents energy delivered to distribution customers.
(b) Primarily Ohio's contractually obligated purchases of OVEC power sold into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	238	137	1,929	2,575
Normal - Heating (b)	184	186	2,103	2,067
Actual - Cooling (c)	308	350	309	350
Normal - Cooling (b)	289	287	292	290

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Net Income
(in millions)

Second Quarter of 2015	$47.7
Changes in Gross Margin:	
Retail Margins	109.2
Off-system Sales	(7.1)
Transmission Revenues	(10.6)
Other Revenues	(4.5)
Total Change in Gross Margin	87.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(41.7)
Depreciation and Amortization	(2.6)
Taxes Other Than Income Taxes	(0.6)
Interest Income	(0.4)
Carrying Costs Income	(3.9)
Allowance for Equity Funds Used During Construction	(0.7)
Interest Expense	2.2
Total Change in Expenses and Other	(47.7)
Income Tax Expense	(12.4)
Second Quarter of 2016	$74.6

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins increased $109 million primarily due to the following:
- A $57 million increase in transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $21 million increase due to a reversal of a regulatory provision resulting from a favorable court decision.
- A $10 million increase in various riders such as Universal Service Fund (USF) and gridSMART®. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
- A $6 million increase in revenues associated with the Distribution Investment Rider (DIR).
- A $4 million increase in carrying charges due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- Margins from Off-system Sales decreased $7 million primarily due to losses from a power contract with OVEC.
- Transmission Revenues decreased $11 million primarily due to the following:
- A $23 million decrease in Network Integrated Transmission Service (NITS) revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

These decreases were partially offset by:

-

A $12 million increase due to a settlement recorded in 2015, a decrease in amortization of the formula rate true-up and the recording of the current year formula rate true-up in 2016.

- Other Revenues decreased $5 million primarily due to decreased pole attachment revenue due to a prior period favorable adjustment.

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

- Other Operation and Maintenance expenses increased $42 million primarily due to the following:
  - A $29 million increase in recoverable PJM expenses.
  - An $8 million increase in recoverable gridSMART® expenses.
  - A $5 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
- Depreciation and Amortization expenses increased $3 million primarily due to the following:
  - A $2 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
  - A $2 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - A $2 million increase due to recoveries of transmission cost rider carrying costs. The increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
  - A $4 million decrease in recoverable gridSMART® depreciation expenses.
- Carrying Costs Income decreased $4 million due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- Income Tax Expense increased $12 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Reconciliation of Six Months Ended June 30, 2015 to Six Months Ended June 30, 2016
Net Income
(in millions)

Six Months Ended June 30, 2015	$ 113.1
Changes in Gross Margin:	
Retail Margins	165.6
Off-system Sales	(15.6)
Transmission Revenues	(40.4)
Other Revenues	(2.4)
Total Change in Gross Margin	107.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(48.9)
Depreciation and Amortization	(4.7)
Taxes Other Than Income Taxes	(0.4)
Interest Income	(0.8)
Carrying Costs Income	(8.5)
Allowance for Equity Funds Used During Construction	(1.4)
Interest Expense	3.2
Total Change in Expenses and Other	(61.5)
Income Tax Expense	(14.0)
Six Months Ended June 30, 2016	$ 144.8

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins increased $166 million primarily due to the following:
- A $118 million increase in transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $21 million increase due to a reversal of a regulatory provision resulting from a favorable court decision.
- A $14 million increase in various riders such as USF and gridSMART®. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
- A $12 million increase in revenues associated with the DIR.
- A $9 million increase in carrying charges due to the collection of carrying costs on deferred capacity charges beginning June 2015.

These increases were partially offset by:

- A $16 million decrease in revenues associated with the recovery of 2012 storm costs under the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $16 million primarily due to losses from a power contract with OVEC.
- Transmission Revenues decreased $40 million primarily due to the following:
-

A $54 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

This decrease was partially offset by:

- A $12 million increase due to a settlement recorded in 2015, a decrease in amortization of the formula rate true-up and the recording of the current year formula rate true-up in 2016.
- Other Revenues decreased $2 million primarily due to decreased pole attachment revenue due to a prior period favorable adjustment.

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

- Other Operation and Maintenance expenses increased $49 million primarily due to the following:
  - A $43 million increase in recoverable PJM expenses.
  - A $16 million increase in recoverable gridSMART® expenses.
  - A $6 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
  - A $4 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $15 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- Depreciation and Amortization expenses increased $5 million primarily due to the following:
  - A $7 million increase due to recoveries of transmission cost rider carrying costs. The increase was offset by a corresponding increase in Retail Margins above.
  - A $6 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
  - A $4 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.

  These increases were partially offset by:
  - A $6 million decrease in recoverable gridSMART® depreciation expenses.
  - A $2 million decrease due to a decrease in capitalized software.
  - A $2 million decrease in DIR recoveries.
- Carrying Costs Income decreased $9 million due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- Interest Expense decreased $3 million primarily due to the maturity of a Senior Unsecured Note in June 2016.
- Income Tax Expense increased $14 million primarily due to an increase in pretax book income.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES				
Electricity, Transmission and Distribution	$728.1	$670.3	$1,484.8	$1,544.5
Sales to AEP Affiliates	1.4	33.2	6.2	75.3
Other Revenues	1.3	2.3	3.4	4.4
TOTAL REVENUES	730.8	705.8	1,494.4	1,624.2
EXPENSES				
Purchased Electricity for Resale	147.8	116.4	312.7	258.5
Purchased Electricity from AEP Affiliates	36.4	146.2	85.5	416.8
Amortization of Generation Deferrals	51.8	35.4	106.9	66.8
Other Operation	173.8	129.8	341.7	276.6
Maintenance	31.9	34.2	65.6	81.8
Depreciation and Amortization	58.3	55.7	119.6	114.9
Taxes Other Than Income Taxes	92.2	91.6	189.8	189.4
TOTAL EXPENSES	592.2	609.3	1,221.8	1,404.8
OPERATING INCOME	138.6	96.5	272.6	219.4
Other Income (Expense):				
Interest Income	0.8	1.2	2.3	3.1
Carrying Costs Income	1.2	5.1	3.1	11.6
Allowance for Equity Funds Used During Construction	1.7	2.4	3.4	4.8
Interest Expense	(29.1)	(31.3)	(60.5)	(63.7)
INCOME BEFORE INCOME TAX EXPENSE	113.2	73.9	220.9	175.2
Income Tax Expense	38.6	26.2	76.1	62.1
NET INCOME	$74.6	$47.7	$144.8	$113.1

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

See Condensed Notes to Condensed

Financial
Statements of
Registrants
beginning on
page 109.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net Income	$74.6	$47.7	$144.8	$113.1
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.2) and $(0.2) for the Three Months Ended June 30, 2016 and 2015, Respectively, and $(0.4) and $(0.4) for the Six Months Ended June 30, 2016 and 2015, Respectively	(0.4)	(0.4)	(0.8)	(0.7)
TOTAL COMPREHENSIVE INCOME	$74.2	$47.3	$144.0	$112.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 321.2	$ 838.8	$ 814.6	$ 5.6	$ 1,980.2
Common Stock Dividends			(87.5)		(87.5)
Net Income			113.1		113.1
Other Comprehensive Loss				(0.7)	(0.7)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$ 321.2	$ 838.8	$ 840.2	$ 4.9	$ 2,005.1
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 321.2	$ 838.8	$ 822.3	$ 4.3	$ 1,986.6
Common Stock Dividends			(150.0)		(150.0)
Net Income			144.8		144.8
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2016	$ 321.2	$ 838.8	$ 817.1	$ 3.5	$ 1,980.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2016 and December 31, 2015
(in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$6.3	$ 3.1
Restricted Cash for Securitized Funding	27.2	27.7
Advances to Affiliates	—	331.1
Accounts Receivable:		
Customers	37.1	46.4
Affiliated Companies	53.2	64.3
Accrued Unbilled Revenues	12.9	1.4
Miscellaneous	0.7	0.4
Allowance for Uncollectible Accounts	(0.2)	(0.2)
Total Accounts Receivable	103.7	112.3
Materials and Supplies	52.6	61.5
Emission Allowances	16.5	24.6
Prepayments and Other Current Assets	18.6	12.9
TOTAL CURRENT ASSETS	224.9	573.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,286.8	2,235.6
Distribution	4,363.0	4,287.7
Other Property, Plant and Equipment	431.5	408.2
Construction Work in Progress	169.5	171.9
Total Property, Plant and Equipment	7,250.8	7,103.4
Accumulated Depreciation and Amortization	2,089.3	2,048.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,161.5	5,054.7
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32.3	32.3
Regulatory Assets	1,004.3	1,113.0
Securitized Assets	73.9	85.9
Long-term Risk Management Assets	0.1	19.2
Deferred Charges and Other Noncurrent Assets	172.0	259.6
TOTAL OTHER NONCURRENT ASSETS	1,282.6	1,510.0
TOTAL ASSETS	$6,669.0	$ 7,137.9

See
Condensed
Notes to
Condensed
Financial
Statements

of Registrants beginning on page 109.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT LIABILITIES		
Advances from Affiliates	$177.1	$ —
Accounts Payable:		
General	136.6	156.4
Affiliated Companies	93.8	88.7
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2016 and December 31, 2015 Amounts Include $45.6 and $45.9, Respectively, Related to Ohio Phase-in-Recovery Funding)	45.6	395.9
Risk Management Liabilities	5.7	3.6
Customer Deposits	63.7	65.4
Accrued Taxes	303.9	528.3
Accrued Interest	31.3	33.0
Other Current Liabilities	97.1	154.3
TOTAL CURRENT LIABILITIES	954.8	1,425.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2016 and December 31, 2015 Amounts Include $117.4 and $139.4, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,740.4	1,761.8
Long-term Risk Management Liabilities	9.0	—
Deferred Income Taxes	1,407.5	1,383.2
Regulatory Liabilities and Deferred Investment Tax Credits	521.0	514.2
Employee Benefits and Pension Obligations	27.9	35.8
Deferred Credits and Other Noncurrent Liabilities	27.8	30.7
TOTAL NONCURRENT LIABILITIES	3,733.6	3,725.7
TOTAL LIABILITIES	4,688.4	5,151.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	817.1	822.3
Accumulated Other Comprehensive Income (Loss)	3.5	4.3
TOTAL COMMON SHAREHOLDER'S EQUITY	1,980.6	1,986.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$6,669.0	$ 7,137.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Six Months Ended June 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$ 144.8	$ 113.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	119.6	114.9
Amortization of Generation Deferrals	106.9	66.8
Deferred Income Taxes	20.6	15.5
Carrying Costs Income	(3.1)	(11.6)
Allowance for Equity Funds Used During Construction	(3.4)	(4.8)
Mark-to-Market of Risk Management Contracts	30.2	9.9
Pension Contributions to Qualified Plan Trust	(7.1)	(7.7)
Property Taxes	113.2	96.3
Purchased Electricity Over/Under-Recovery, Net	(21.1)	(22.9)
Deferral of Ohio Capacity Costs, Net	—	(30.7)
Change in Other Noncurrent Assets	(36.2)	22.9
Change in Other Noncurrent Liabilities	8.6	23.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8.6	38.2
Materials and Supplies	(3.0)	(14.7)
Accounts Payable	(4.8)	(68.1)
Accrued Taxes, Net	(226.8)	(99.7)
Other Current Assets	(2.2)	(0.8)
Other Current Liabilities	(39.0)	(24.1)
Net Cash Flows from Operating Activities	205.8	216.0
INVESTING ACTIVITIES		
Construction Expenditures	(193.2)	(236.0)
Change in Restricted Cash for Securitized Funding	0.5	—

Change in Advances to Affiliates, Net	331.1	124.7
Proceeds from Notes Receivable – Affiliated	—	86.0
Other Investing Activities	6.2	6.3
Net Cash Flows from (Used for) Investing Activities	144.6	(19.0)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	177.1	—
Retirement of Long-term Debt – Nonaffiliated	(372.8)	(108.2)
Principal Payments for Capital Lease Obligations	(2.0)	(1.9)
Dividends Paid on Common Stock	(150.0)	(87.5)
Other Financing Activities	0.5	1.1
Net Cash Flows Used for Financing Activities	(347.2)	(196.5)
Net Increase in Cash and Cash Equivalents	3.2	0.5
Cash and Cash Equivalents at Beginning of Period	3.1	2.9
Cash and Cash Equivalents at End of Period	$ 6.3	$ 3.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 60.0	$ 61.3
Net Cash Paid for Income Taxes	132.3	20.5
Noncash Acquisitions Under Capital Leases	1.7	1.7
Construction Expenditures Included in Current Liabilities as of June 30,	23.1	42.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 109.

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PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in millions of KWhs)			
Retail:				
Residential	1,375	1,324	2,741	2,840
Commercial	1,317	1,329	2,472	2,460
Industrial	1,398	1,377	2,668	2,631
Miscellaneous	316	317	586	593
Total Retail	4,406	4,347	8,467	8,524
Wholesale	46	47	113	138
Total KWhs	4,452	4,394	8,580	8,662

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in degree days)			
Actual - Heating (a)	4	10	782	1,176
Normal - Heating (b)	41	41	1,104	1,088
Actual - Cooling (c)	694	646	712	659
Normal - Cooling (b)	651	652	665	666

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

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Second Quarter of 2016 Compared to Second Quarter of 2015
Reconciliation of Second Quarter of 2015 to Second Quarter of 2016
Net Income
(in millions)

Second Quarter of 2015	$27.1
Changes in Gross Margin:	
Retail Margins (a)	16.0
Other Revenues	0.1
Total Change in Gross Margin	16.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(5.2)
Depreciation and Amortization	(7.6)
Taxes Other Than Income Taxes	0.2
Interest Income	0.1
Allowance for Equity Funds Used During Construction	(0.8)
Interest Expense	(0.5)
Total Change in Expenses and Other	(13.8)
Income Tax Expense	(0.5)
Second Quarter of 2016	$28.9

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

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

- Retail Margins increased $16 million primarily due to the following:
  - An $11 million increase primarily related to interim base rate increases implemented in January 2016. This increase in retail margins has corresponding increases in other items below.
  - A $2 million increase in weather-related usage primarily due to a 7% increase in cooling degree days.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $5 million primarily due to the following:
  - A $6 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $3 million increase in distribution expenses primarily due to increased vegetation management expenses.

  These increases were partially offset by:
  - A $4 million decrease in generation plant maintenance expenses.
- Depreciation and Amortization expenses increased $8 million primarily due to the following:
  - A $9 million increase primarily related to interim rate increases.

  This increase was partially offset by:
  - A $2 million decrease in amortization related to the gridSMART® Project.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015
Reconciliation of Six Months Ended June 30, 2015 to Six
Months Ended June 30, 2016
Net Income
(in millions)

Six Months Ended June 30, 2015	$40.8
Changes in Gross Margin:	
Retail Margins (a)	25.0
Off-system Sales	(0.1)
Other Revenues	1.0
Total Change in Gross Margin	25.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.9)
Depreciation and Amortization	(13.4)
Taxes Other Than Income Taxes	(0.2)
Interest Income	0.2
Allowance for Equity Funds Used During Construction	0.2
Interest Expense	(0.3)
Total Change in Expenses and Other	(21.4)
Income Tax Expense	(0.7)
Six Months Ended June 30, 2016	$44.6

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

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

- Retail Margins increased $25 million primarily due to the following:
  - A $25 million increase primarily related to interim base rate increases implemented in January 2016. This increase in retail margins has corresponding increases in other items below.

  This increase was partially offset by:
  - A $3 million decrease in weather-related usage primarily due to a 34% decrease in heating degree days.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $8 million primarily due to the following:
  - A $7 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $3 million increase in general and administrative expenses.
  - A $2 million increase in distribution expenses primarily due to amortization of 2013 storm restoration expenses beginning in May 2015.

  These increases were partially offset by:
  - A $3 million decrease in generation plant maintenance expenses.
- Depreciation and Amortization expenses increased $13 million primarily due to the following:
  - A $16 million increase primarily related to interim rate increases.

This increase was partially offset by:

- A $3 million decrease in amortization related to the gridSMART® Project.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2016 and 2015
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES				
Electric Generation, Transmission and Distribution	$298.6	$317.6	$570.4	$622.3
Sales to AEP Affiliates	0.9	1.1	1.9	2.4
Other Revenues	0.7	0.8	2.2	1.6
TOTAL REVENUES	300.2	319.5	574.5	626.3
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	11.1	53.0	26.6	138.6
Purchased Electricity for Resale	91.2	85.1	184.5	150.6
Purchased Electricity from AEP Affiliates	0.4	—	0.4	—
Other Operation	67.9	61.0	130.8	121.8
Maintenance	24.2	25.9	46.0	47.1
Depreciation and Amortization	37.4	29.8	72.7	59.3
Taxes Other Than Income Taxes	9.0	9.2	18.7	18.5
TOTAL EXPENSES	241.2	264.0	479.7	535.9