PROSPECTUS

AEP Transmission Company, LLC

Offers to Exchange

$125,030,000 aggregate principal amount of its 3.10% Senior Notes, Series F due 2026 and $500,000,000 aggregate principal amount of its 3.75% Senior Notes, Series I due 2047, each of which have been registered under the Securities Act of 1933, as amended, for any and all of its outstanding

3.10% Senior Notes, Series D due 2026 and 3.75% Senior Notes, Series H due 2047, respectively

We are conducting the Offers to Exchange described above, or Exchange Offers, in order to provide you with an opportunity to exchange your unregistered outstanding notes referred to above, or Outstanding Notes, for substantially identical notes of the same series that have been registered under the Securities Act, which we refer to as Exchange Notes.

The Exchange Offers

- We will exchange all Outstanding Notes that are validly tendered and not validly withdrawn for an equal principal amount of Exchange Notes that are registered under the Securities Act.
- You may withdraw tenders of Outstanding Notes at any time prior to the expiration of the Exchange Offers.
- The Exchange Offers expire at 5:00 p.m., New York City time, on May 7, 2018, unless extended. We do not currently intend to extend the Expiration Date.
- The exchange of Outstanding Notes for Exchange Notes in the Exchange Offers will not be a taxable event to holders for United States federal income tax purposes.
- The terms of the Exchange Notes to be issued in the Exchange Offers are substantially identical to the Outstanding Notes of the respective series, except that the Exchange Notes will be registered under the Securities Act, and do not have any transfer restrictions, registration rights or additional interest provisions.

Results of the Exchange Offers

- Except as prohibited by applicable law, the Exchange Notes may be sold in the over-the-counter market, in negotiated transactions or through a combination of such methods. There is no existing market for the Exchange Notes to be issued, and we do not plan to list the Exchange Notes on a national securities exchange or market.
- We will not receive any proceeds from the Exchange Offers.

All untendered Outstanding Notes will remain outstanding and continue to be subject to the restrictions on transfer set forth in the Outstanding Notes and in the indenture governing the Outstanding Notes. In general, the Outstanding Notes may not be offered or sold, unless registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. Other than in connection with the Exchange Offers, we do not currently anticipate that we will register the Outstanding Notes under the Securities Act.

Each broker-dealer that receives Exchange Notes for its own account in the Exchange Offers must acknowledge that it will deliver a prospectus in connection with any resale of those Exchange Notes. The letter of transmittal states that by so acknowledging and delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act.

This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Notes received in exchange for Outstanding Notes where the broker-dealer acquired such Outstanding Notes as a result of market-making or other trading activities. We have agreed that, for a period of 180 days after the Expiration Date, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale. See “Plan of Distribution.”

See “Risk Factors” beginning on page 11 for a discussion of certain risks that you should consider before participating in the Exchange Offers.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of the Exchange Notes to be distributed in the Exchange Offers or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is April 6, 2018.

In making your investment decision, you should rely only on the information contained in or incorporated by reference into this prospectus. We have not authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not making an offer of the Exchange Notes in any jurisdiction where the offer thereof is not permitted. The information contained in this prospectus speaks only as of the date of this prospectus.

This prospectus incorporates by reference important business and financial information about us from documents filed with the SEC that have not been included herein or delivered herewith. Information incorporated by reference is available without charge at the website that the SEC maintains at http://www.sec.gov, as well as from other sources. See “Available Information and Incorporation by Reference.” In addition, you may request a copy of such document, at no cost, by writing or calling us at the following address or telephone number: Investor Relations, American Electric Power Service Corporation, 1 Riverside Plaza, Columbus, OH 43215; 614-716-1000. In order to receive timely delivery of those materials, you must make your requests no later than five business days before expiration of the applicable exchange offer, or May 7, 2018, the present expiration date of the exchange offers.

References to “AEPTCo,” “Company,” “we,” “us” and “our” in this prospectus are references to AEP Transmission Company, LLC specifically or, if the context requires, to AEP Transmission Company, LLC and its subsidiaries, collectively.

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SUMMARY

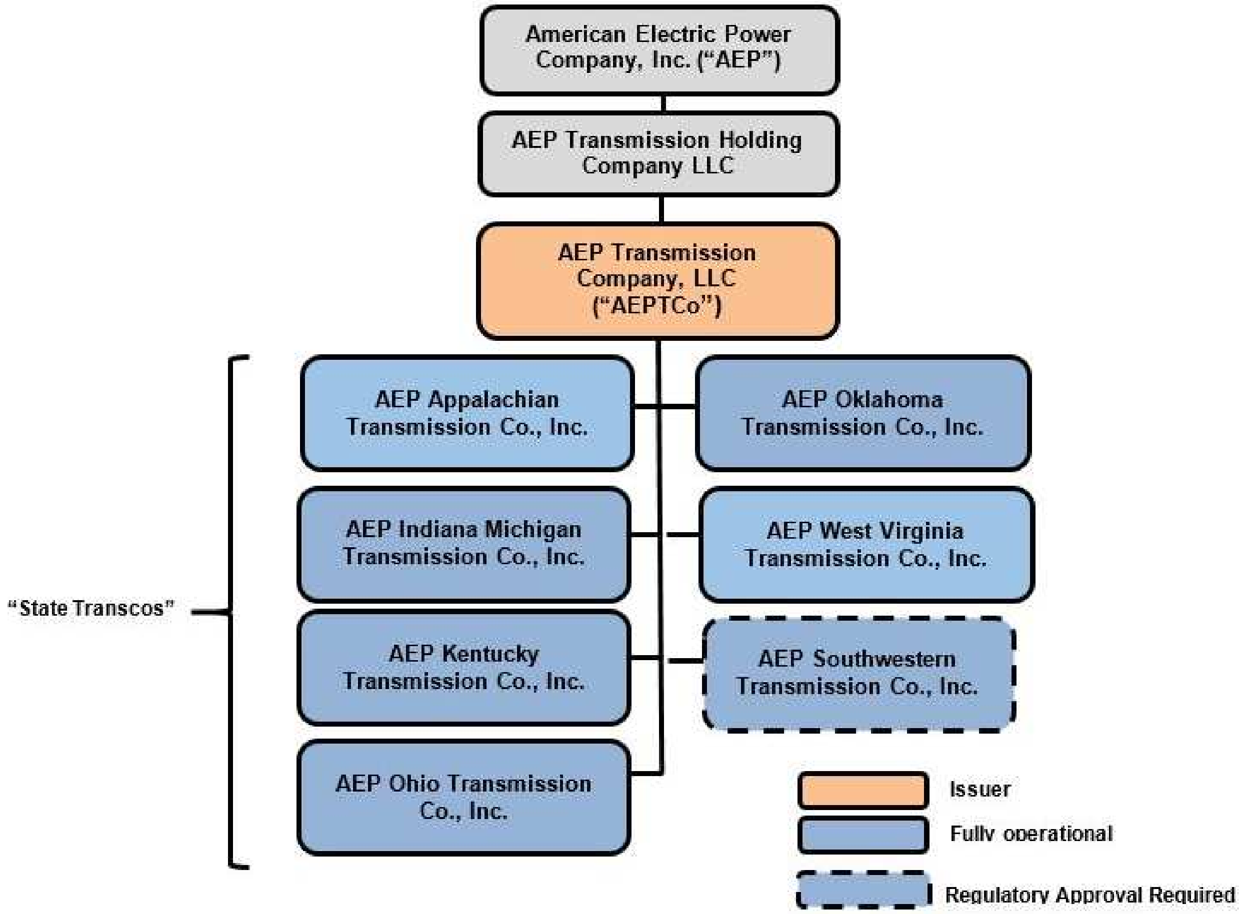
This summary highlights certain information concerning the Company and this offering that may be contained elsewhere in this prospectus. This summary is not complete and does not contain all the information that may be important to you. You should read this prospectus in its entirety before making an investment decision.

AEP Transmission Company, LLC

Overview and Organizational Structure

AEP Transmission Company, LLC ("AEPTCo" or the "Company"), a Delaware limited liability company organized in 2006, is the holding company of seven regulated transmission-only electric utilities. AEPTCo is an indirect wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP").

Our business consists of developing and building new transmission facilities at the request of the regional transmission organizations in which we operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. Our principal executive offices are located at 1 Riverside Plaza, Columbus, Ohio 43215 (Telephone number (614) 716-1000).



State Transcos

AEPTCo's seven wholly-owned public utility companies are (collectively referred to herein as the "State Transcos"):

- AEP Appalachian Transmission Company, Inc. ("APTCo"),
- AEP Indiana Michigan Transmission Company, Inc. ("IMTCo"),
- AEP Kentucky Transmission Company, Inc. ("KTCo"),
- AEP Ohio Transmission Company, Inc. ("OHTCo"),
- AEP West Virginia Transmission Company, Inc. ("WVTCo"),
- AEP Oklahoma Transmission Company, Inc. ("OKTCo") and
- AEP Southwestern Transmission Company, Inc. ("SWTCo").

The State Transcos are independent of but overlay AEP's existing electric utility operating companies: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and Wheeling Power Company (collectively, the "AEP Operating Companies"). The State Transcos develop, own, operate, and maintain their respective transmission assets. Assets of the State Transcos interconnect to transmission facilities owned by the AEP Operating Companies and unaffiliated transmission owners within the footprints of PJM and SPP. PJM and SPP are regional transmission organizations ("RTOs") mandated by the Federal Energy Regulatory Commission ("FERC") to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. PJM is a regional transmission organization serving approximately 65 million people throughout 13 states and the District of Columbia. APTCo, IMTCo, KTCo, OHTCo and WVTCo are located within PJM. SPP is a regional transmission organization serving over 18 million people in fourteen states. OKTCo and SWTCo are located within SPP.

Individual State Transcos (a) have obtained the approvals necessary to operate in Indiana, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, (b) are authorized to submit projects for commission approval in Virginia and (c) have been granted consent to enter into a joint license agreement that will support investment in Tennessee. The application for regulatory approval to operate in Louisiana is under consideration, while the application for regulatory approval to operate in Arkansas was denied.

Regulation

The State Transcos are regulated for rate-making purposes exclusively by FERC and earn revenues through tariff rates charged for the use of their electric transmission systems. The State Transcos establish transmission rates each year through formula rate filings with FERC. The rate filings calculate the revenue requirement needed to cover the costs of operation and debt service and to earn an allowed return on equity. These rates are then included in the Open Access Transmission Tariffs ("OATT") for SPP and PJM. SPP and PJM collect the revenue requirement from transmission customers under their respective OATTs. The transmission customers under the OATTs include the AEP Operating Companies, other investor-owned utilities, electric cooperatives, municipal entities and power marketers.

The public service commissions in the states where our State Transcos' assets are located do not have jurisdiction over the State Transcos' rates or terms and conditions of service. However, certain transmission facilities are subject to certification and/or siting and financing requirements specific to each state. While these proceedings require a statement and justification of need, they also determine line routes and substation locations with the least impact to the environment and general public. The state public service commission or a designated entity will review the State Transco's application to certify the project.

Operations

As transmission-only companies, our State Transcos function as conduits, allowing for power from generators to be transmitted to local distribution systems. The transmission of electricity by our State Transcos is a central function to the provision of electricity to residential, commercial and industrial end-use consumers. American Electric Power Service Corporation ("AEPSC") has executed a services agreement pursuant to which AEPSC has agreed to provide services to each of the State Transcos. AEPSC is an AEP service subsidiary that provides management and professional services to AEP and its subsidiaries. AEPSC provides four categories of service to the State Transcos: project evaluation and permitting services, project development services, operation and management services and business services, including billing, insurance, human resources and IT services. All of these services are provided at cost. Additionally, each State Transco has executed a services agreement with the respective incumbent AEP Operating Company in its state or footprint.

Existing and Forecasted Projects

The State Transcos are geographically diverse and have assets in service or under construction across two RTOs and in seven states, with additional states pending approval. We anticipate the need for extensive additional investment in transmission infrastructure within PJM and SPP to maintain the required level of grid reliability, resiliency, security and efficiency and to address an aging transmission infrastructure. We also foresee the need to construct additional transmission facilities based on changes in generating resources, such as wind or solar projects, generation additions or retirements, and additional new customer interconnections. We will continue our investment to enhance physical and cyber security of our assets, and are also investing in improving the telecommunication network that supports the operation and control of the grid. Finally, our fundamental obligation to meet state, federal, regulatory and industry standards will continue to drive investment in this category of projects.

A key part of our business is replacing and upgrading transmission facilities, assets and components of the existing AEP System as needed to maintain reliability. Over 5,800 miles of AEP's transmission lines were built more than seventy years ago. Significant quantities of major transmission equipment, such as transformers and circuit breakers, on AEP's grid are also at or near the end of their useful life. The State Transcos provide the capability to upgrade existing facilities due to their condition as a result of their age.

Business Strategy

AEPTCo's business strategy is to own, operate, maintain and invest in transmission infrastructure in order to maintain and enhance system integrity and grid reliability, grid security, safety, reduce transmission constraints and facilitate interconnections of new generating resources and new wholesale customers, as well as enhance competitive wholesale electricity markets. This strategy will be implemented by the State Transcos through the following types of projects:

- Regional Projects: Projects assigned to the AEP System as a result of the regional planning initiatives conducted by PJM or SPP. The RTOs identify the need for transmission in support of regional reliability, transmission service, congestion mitigation, public policy, to support the integration of new generation resources and to support the retirement of generation resources. Regional Projects must be awarded by PJM or SPP in a process approved by FERC under Order 1000, and generally contemplates more than one bidder for any particular Regional Project.

- Local Projects: Improvements to local area reliability by upgrading, rebuilding or replacing existing, aging infrastructure at the AEP Operating Companies. AEP evaluates several criteria to determine the need for Local Projects. These criteria include age, recorded performance issues, condition assessment, anticipated maintenance requirements and criticality to the grid. Projects are assigned to the State Transcos based upon a defined set of criteria. Local projects also include new interconnections discussed below.

- New Interconnections: Construction of new facilities to support customer points of delivery.

Transmission investment across AEP is primarily driven by the need to replace infrastructure whose performance and condition significantly increase the risk of failure, our desire to enhance reliability at a local level to improve the customer experience, compliance with regulatory, industry, and governmental standards, requirements to improve telecommunication capability to keep up with changing technologies, and the obligation to address grid limitations identified by the RTOs. The State Transcos are not limited to investing in projects addressing particular transmission drivers. AEP has developed thorough project selection guidelines that help determine which transmission assets can be built, owned and operated by the State Transcos. In essence, the need on the transmission grid determines the transmission project and the project selection guidelines help determine which components of the transmission project will be placed in the State Transcos.

Generally, greenfield transmission, partial or complete refurbishment of extra high voltage transmission, and complete refurbishment of lower voltage transmission assets qualify for transmission investment in the State Transcos. In the foreseeable future, AEPTCo expects the majority of its transmission investment to go towards replacing existing assets, local reliability and upgrading telecommunications and operational enhancements.

Each State Transco is responsible for developing, constructing, owning, operating, and maintaining its respective transmission facilities.

Company Strengths

We believe we have the following key competitive strengths to enable us to carry out our business strategy:

Transparent Transmission Business with Diversity of Projects

- High transparency as a transmission-only business under FERC regulation;
- Geographic diversity across two RTOs and seven states, with an additional state pending approval; and
- Project pipeline consists of local and regional projects connected to AEP's existing system.

Favorable Regulatory Oversight

- FERC rate-regulated utility benefiting from high level of certainty from FERC's recovery mechanisms and revenue collection through PJM and SPP; and

- Annual formula rate-making process with true-ups.

Strong Parent Ownership
- Wholly-owned by AEP;
- AEPTCo is core to AEP's corporate growth strategy; and
- AEP has invested $1.6 billion in equity contributions to AEPTCo since 2009.

Conservative Capitalization and Strong Financial Profile
- AEPTCo has a strong credit profile;
- Indenture debt covenant limits external debt at State Transcos which limits structural subordination for debt at the AEPTCo level; and
- Strong liquidity profile, includes access to either short-term capital through the AEP utility money pool or direct borrowing from AEP.

The Exchange Offers

In November 2016 and September 2017, we issued the Outstanding Notes in transactions not subject to the registration requirements of the Securities Act of 1933, as amended, or "Securities Act". The term "2026 Exchange Notes" refers to the 3.10% Senior Notes, Series F due 2026 and the term "2047 Exchange Notes" refers to the 3.75% Senior Notes, Series I due 2047, each as registered under the Securities Act, and all of which collectively are referred to as the "Exchange Notes." The term "Notes" collectively refers to the Outstanding Notes and the Exchange Notes.

General

In connection with the issuance of the Outstanding Notes, we entered into a registration rights agreement with representatives of the initial purchasers of the Outstanding Notes pursuant to which we agreed, among other things, to deliver this prospectus to you and to use commercially reasonable efforts to complete the Exchange Offers within 315 days after the date of original issuance of the Outstanding Notes. You are entitled to exchange in the Exchange Offers your Outstanding Notes for the respective series of Exchange Notes that are identical in all material respects to the Outstanding Notes except:

Ÿ the Exchange Notes have been registered under the Securities Act and, therefore, will not be subject to the restrictions on transfer applicable to the Outstanding Notes (except as described in "The Exchange Offers-Resale of Exchange Notes" and "Description of the Exchange Notes-Form; Transfers; Exchanges");

Ÿ the Exchange Notes are not entitled to any registration rights which are applicable to the Outstanding Notes under the registration rights agreement, including any rights to additional interest for failure to comply with the registration rights agreement; and

Ÿ the Exchange Notes will bear different CUSIP numbers.

The Exchange Offers

We are offering to exchange:

Ÿ $125,030,000 aggregate principal amount of 3.10% Senior Notes, Series F due 2026 that have been registered under the Securities Act for any and all of our existing 3.10% Senior Notes, Series D due 2026 and

Ÿ $500,000,000 aggregate principal amount of 3.75% Senior Notes, Series I due 2047 that have been registered under the Securities Act for any and all of our existing 3.75% Senior Notes, Series H due 2047.

You may only exchange Outstanding Notes in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof. Any untendered Outstanding Notes must also be in a minimum denomination of $2,000.

Resale

Based on an interpretation by the staff of the Securities and Exchange Commission, or SEC, set forth in no-action letters issued to third parties, we believe that the Exchange Notes issued pursuant to the Exchange Offers in exchange for the Outstanding Notes may be offered for resale, resold and otherwise transferred by you (unless you are our "affiliate" within the meaning of Rule 405 under the Securities Act) without compliance with the registration and prospectus delivery provisions of the Securities Act, provided that:

Ÿ you are acquiring the Exchange Notes in the ordinary course of your business; and

Ÿ you have not engaged in, do not intend to engage in, and have no arrangement or understanding with any person to participate in, a distribution of the Exchange Notes.

Any holder of Outstanding Notes who:

Ÿ is our affiliate;

Ÿ does not acquire Exchange Notes in the ordinary course of its business; or

Ÿ tenders its Outstanding Notes in the Exchange Offers with the intention to participate, or for the purpose of participating, in a distribution of Exchange Notes

cannot rely on the position of the staff of the SEC enunciated in the staff's no-action letters to *Morgan Stanley & Co. Incorporated* (available June 5, 1991) and *Exxon Capital Holdings Corporation* (available May 13, 1988), as interpreted in *Shearman & Sterling* (available July 2, 1993), or similar no-action letters and, in the absence of an exemption therefrom, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the Exchange Notes.

If you are a broker-dealer and receive Exchange Notes for your own account in exchange for Outstanding Notes that you acquired as a result of market-making activities or other trading activities, you must acknowledge that you will deliver this prospectus in connection with any resale of the Exchange Notes and that you are not our affiliate and did not purchase your Outstanding Notes from us or any of our affiliates. See "Plan of Distribution."

Our belief that the Exchange Notes may be offered for resale without compliance with the registration or prospectus delivery provisions of the Securities Act is based on interpretations of the SEC for other exchange offers that the SEC expressed in some of its no-action letters to other issuers in exchange offers like ours. We have not sought a no-action letter in connection with the Exchange Offers, and we cannot guarantee that the SEC would make a similar decision about our Exchange Offers. If our belief is wrong, or if you cannot truthfully make the representations mentioned above, and you transfer any Exchange Note issued to you in the Exchange Offers without meeting the registration and prospectus delivery requirements of the Securities Act, or without an exemption from such requirements, you could incur liability under the Securities Act. We are not indemnifying you for any such liability.

Expiration Date

The Exchange Offers will expire at 5:00 p.m., New York City time, on May 7, 2018, unless

	extended by us. We do not currently intend to extend the Expiration Date.
Withdrawal	You may withdraw the tender of your Outstanding Notes at any time prior to the expiration of the Exchange Offers. We will return to you any of your Outstanding Notes that are not accepted for any reason for exchange, without expense to you, promptly after the expiration or termination of the Exchange Offers.
Conditions to the Exchange Offers	Each Exchange Offer is subject to customary conditions. We reserve the right to waive any defects, irregularities or conditions to exchange as to particular Outstanding Notes. See "The Exchange Offers-Conditions to the Exchange Offers."
Procedures for Tendering Outstanding Notes	If you wish to participate in any of the Exchange Offers, you must either:

- complete, sign and date the applicable accompanying letter of transmittal, or a facsimile of the letter of transmittal, in accordance with the instructions contained in this prospectus and the letter of transmittal, and mail or deliver such letter of transmittal or facsimile thereof, together with the Outstanding Notes to be exchanged for Exchange Notes, and any other required documents, to the Exchange Agent at the address set forth on the cover page of the letter of transmittal; or

- if you hold Outstanding Notes through The Depository Trust Company, or "DTC", comply with DTC's Automated Tender Offer Program procedures described in this prospectus, by which you will agree to be bound by the letter of transmittal.

By signing, or agreeing to be bound by, the letter of transmittal, you will represent to us that, among other things:

- any Exchange Notes received by you will be acquired in the ordinary course of your business;
- you have no arrangements or understanding with any person to participate in the distribution of the Exchange Notes within the meaning of the Securities Act;
- you are not engaged in, and do not intend to engage in, the distribution of the Exchange Notes;
- you are not an "affiliate," as defined in Rule 405 of the Securities Act, of the Company or, if you are an affiliate, you will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable; and
- if you are a broker-dealer, you will receive Exchange Notes for your own account in exchange for Outstanding Notes that were acquired as a result of market-making activities or other trading activities, and you will deliver a prospectus in connection with any resale of such Exchange Notes.

Special Procedures for Beneficial Owners	If you are a beneficial owner of Outstanding Notes that are registered in the name of a broker, dealer, commercial bank, trust company or other nominee, and you wish to tender those Outstanding Notes in any of the Exchange Offers, you should contact the registered holder promptly and instruct the registered holder to tender those Outstanding Notes on your behalf. If you wish to tender on your own behalf, you must, prior to completing and executing the letter of transmittal and delivering your Outstanding Notes, either make appropriate arrangements to register ownership of the Outstanding Notes in your name or obtain a properly completed bond power from the registered holder. The transfer of registered ownership may take considerable

	time and may not be able to be completed prior to the Expiration Date.
Guaranteed Delivery Procedures	If you wish to tender your Outstanding Notes and your Outstanding Notes are not immediately available, or you cannot deliver your Outstanding Notes, the letter of transmittal or any other required documents, or you cannot comply with the procedures under DTC's Automated Tender Offer Program for transfer of book-entry interests prior to the Expiration Date, you must tender your Outstanding Notes according to the guaranteed delivery procedures set forth in this prospectus under "The Exchange Offers-Guaranteed Delivery Procedures."
Effect on Holders of Outstanding Notes	As a result of the making of, and upon acceptance for exchange of all validly tendered Outstanding Notes pursuant to the terms of, the Exchange Offers, we will have fulfilled a covenant under the registration rights agreement. Accordingly, we will not be required to pay additional interest on the Outstanding Notes under the circumstances described in the registration rights agreement. If you do not tender your Outstanding Notes in any of the Exchange Offers, you will continue to be entitled to all the rights and subject to all the limitations applicable to the Outstanding Notes as set forth in the Indenture (as defined below), except we will not have any further obligation to you to provide for the exchange and registration of untendered Outstanding Notes under the registration rights agreement. To the extent that Outstanding Notes are tendered and accepted in the Exchange Offers, the trading market for Outstanding Notes that are not so tendered and accepted could be adversely affected.

Consequences of Failure to Exchange	All untendered Outstanding Notes will remain outstanding and continue to be subject to the restrictions on transfer set forth in the Outstanding Notes and in the Indenture. In general, the Outstanding Notes may not be offered or sold unless registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. Other than in connection with the Exchange Offers, we do not currently anticipate that we will register the Outstanding Notes under the Securities Act.
United States Federal Income Tax Consequences	The exchange of Outstanding Notes in the Exchange Offers will not be a taxable event to holders for United States federal income tax purposes. See "Material United States Federal Income Tax Consequences Of The Exchange Offers."
Use of Proceeds	We will not receive any proceeds from the issuance of the Exchange Notes in the Exchange Offers. See "Use of Proceeds."
Exchange Agent	The Bank of New York Mellon Trust Company, N.A. is the Exchange Agent for the Exchange Offers. Any questions and requests for assistance with respect to accepting or withdrawing from the Exchange Offers, requests for additional copies of this prospectus or of the letter of transmittal and requests for the notice of guaranteed delivery should be directed to the Exchange Agent. The address and telephone number of the Exchange Agent are set forth in the section captioned "The Exchange Offers-Exchange Agent."

The Exchange Notes

The summary below describes the principal terms of the Exchange Notes. Certain of the terms and conditions described below are subject to important limitations and exceptions. The "Description of the Exchange Notes" section of this prospectus contains more detailed descriptions of the terms and conditions of the Outstanding Notes and Exchange Notes. The Exchange Notes will have terms identical in all material respects to the respective series of Outstanding Notes, except that the Exchange Notes will not contain certain terms with respect to transfer restrictions, registration rights and additional interest for failure to observe certain obligations in the registration rights agreement.

Issuer	AEP Transmission Company, LLC.
The Exchange Notes	$125,030,000 principal amount of 3.10% Senior Notes, Series F due 2026 and $500,000,000 principal amount of 3.75% Senior Notes, Series I due 2047.
Maturity	December 1, 2026 for 2026 Exchange Notes and December 1, 2047 for 2047 Exchange Notes.
Interest Rate	3.10% per annum for 2026 Exchange Notes and 3.75% per annum for 2047 Exchange Notes.
Interest Payment Dates	June 1 and December 1 of each year, beginning on June 1, 2018.
Ranking	The Exchange Notes are our senior unsecured obligations and will rank equally in right of payment with all our other senior unsecured obligations and will be effectively subordinated to all of our secured debt, of which we have none outstanding as of March 1, 2018.
Optional Redemption	At any time prior to September 1, 2026, we may redeem the 2026 Exchange Notes at any time, in whole or in part, at a "make whole" redemption price equal to the greater of (1) the principal amount being redeemed or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the 2026 Exchange Notes being redeemed that would be due if such 2026 Exchange Notes matured on September 1, 2026, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined herein), plus 15 basis points, plus in each case accrued and unpaid interest to the redemption date. At any time prior to June 1, 2047, we may redeem the 2047 Exchange Notes at any time, in whole or in part, at a "make whole" redemption price equal to the greater of (1) the principal amount being redeemed or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the 2047 Exchange Notes being redeemed that would be due if such 2047 Exchange Notes matured on June 1, 2047, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined herein), plus 15 basis points, plus in each case accrued and unpaid interest to the redemption date. At any time on or after September 1, 2026, we may redeem the 2026 Exchange Notes in whole or in part at 100% of the principal amount of the 2026 Exchange Notes being redeemed, plus accrued and unpaid interest thereon to but excluding the date of redemption. At any time on or after June 1, 2047, we may redeem the 2047 Exchange Notes in whole or in part at 100% of the principal amount of the 2047 Exchange Notes being redeemed, plus accrued and unpaid interest thereon to but excluding the date of redemption.

Certain Covenants	The Indenture (as defined herein) limits our ability to incur Liens (as defined herein), does not permit Consolidated Priority Debt (as defined herein) to exceed 10% of Consolidated Tangible Net Assets (as defined herein) and limits our ability to merge, consolidate or sell all or substantially all of our

	assets as an entirety. These limitations are subject to a number of important qualifications and exceptions. For more information, see "Description of the Exchange Notes-Certain Covenants."
Absence of Established Market for the Exchange Notes	We do not plan to have the Exchange Notes listed on any securities exchange or included in any automated quotation system. There is no existing trading market for the Exchange Notes, and there can be no assurance regarding any future development of a trading market for the Exchange Notes, the price at which holders of the Exchange Notes may be able to sell their Exchange Notes or the ability of such holders to sell their Exchange Notes at all.
Form of Notes	The Exchange Notes will be issued in fully registered book-entry form and each series of Exchange Notes will be represented by one or more global certificates, which will be deposited with or on behalf of DTC and registered in the name of DTC's nominee. Beneficial interests in global certificates will be shown on, and transfers thereof will be effected only through, records maintained by DTC and its direct and indirect participants, and your interest in any global certificate may not be exchanged for certificated Notes, except in limited circumstances described herein. See "Description of the Exchange Notes-Book-Entry Only Issuance-The Depository Trust Company."
Trustee	The Bank of New York Mellon Trust Company, N.A.
Governing Law	The Indenture is, and the Exchange Notes will be, governed by, and construed in accordance with, the laws of the State of New York.

RISK FACTORS

An investment in the Notes, including a decision to tender your Outstanding Notes in the Exchange Offers, involves a number of risks. Risks described below should be carefully considered together with the other information included in this prospectus. Any of the events or circumstances described as risks below could result in a significant or material adverse effect on our business, results of operations, cash flows or financial condition, and a corresponding decline in the market price of or our ability to repay, the Notes. The risks and uncertainties described below may not be the only risks and uncertainties that we face. Additional risks and uncertainties not currently known may also result in a significant or material adverse effect on our business, results of operations, cash flow or financial condition.

Risks Related to Our Business

Certain elements of our State Transcos' formula rates can be and have been challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus have an adverse effect on our business, financial condition, results of operations and cash flows.

Our State Transcos provide transmission service under rates regulated by the FERC. The FERC has approved the cost-based formula rate templates used by our State Transcos to calculate their respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of our State Transcos' rates accepted or approved by the FERC, including the formula rate templates, the rates of return on the actual equity portion of their respective capital structures and the approved targeted capital structures, are subject to challenge by interested parties at the FERC, or by the FERC on its own initiative. In addition, interested parties may challenge the annual implementation and calculation by our State Transcos of their projected rates and formula rate true up pursuant to their approved formula rate templates under the State Transcos' formula rate implementation protocols. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC will make appropriate prospective adjustments to them and/or disallow any of our State Transcos' inclusion of those aspects in the rate setting formula.

In October 2016, several parties filed a complaint with the FERC claiming that the base return on common equity used by the State Transcos that operate in PJM in calculating formula transmission rates under the PJM OATT, is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In June 2017, a similar complaint was filed with the FERC claiming that the base return on common equity used by the State Transcos that operate in SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to our State Transcos, particularly if rates for delivered electricity increase substantially.

Our actual capital investment may be lower than planned, which would cause a lower than anticipated rate base and would therefore result in lower revenues and earnings compared to our current expectations.

Each of our State Transcos' rate base, revenues and earnings are determined in part by additions to property, plant and equipment and when those additions are placed in service. We anticipate making significant capital investments over the next several years; however, the amounts could change significantly due to factors beyond our control. If our State Transcos' capital investment and the resulting in-service property, plant and equipment are lower than anticipated for any reason, our State Transcos will have a lower than anticipated rate base, thus causing their revenue requirements and future earnings to be lower than anticipated.

Changes in energy laws, regulations or policies could impact our business, financial condition, results of operations and cash flows.

Each of our State Transcos is regulated by the FERC as a "public utility" under federal law and is a transmission owner in PJM or SPP. We cannot predict whether the approved rate methodologies for any of our State Transcos will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to the FERC, modify existing law or provide the FERC or another entity with increased authority to regulate transmission matters. We cannot predict whether, and to what extent, our State Transcos may be affected by any such changes in federal energy laws, regulations or policies in the future. While our State Transcos are subject to FERC's exclusive jurisdiction for purposes of rate regulation, changes in state laws affecting other matters, such as transmission siting and construction, could limit investment opportunities available to us.

We depend on the AEP Operating Companies for a substantial portion of our revenues.

For the year ended December 31, 2017, AEP Operating Companies were responsible for approximately 80% of the consolidated transmission revenues of AEPTCo. We expect that AEP Operating Companies will continue to be our principal transmission service customers for the foreseeable future.

Most of the real property rights on which our assets are situated result from affiliate license agreements and are dependent on the terms of the underlying easements and other rights of our affiliates.

We do not hold title to the majority of real property on which our electric transmission assets are located. Instead, under the provisions of certain affiliate contracts, we are permitted to occupy and maintain our facilities upon real property held by the respective AEP Operating Companies that overlay our operations. Our ability to continue to occupy such real property is dependent upon the terms of such affiliate contracts and upon the underlying real property rights of the AEP Operating Companies, which may be encumbered by easements, mineral rights and other similar encumbrances that may affect the use of such real property. We can give no assurance that (i) we will continue to be affiliates of the AEP Operating Companies, (ii) suitable replacement arrangements can be obtained in the event that the AEP Operating Companies are not our affiliates, and (iii) the underlying easements and other rights are sufficient to permit us to operate our assets in a manner free from interruption.

We contract with third parties and affiliates to provide services for certain aspects of our business. If any of these agreements are terminated, we may face a shortage of labor or replacement contractors to provide the services formerly provided by these third parties.

We enter into various agreements and arrangements with third parties and affiliates to provide services for construction, maintenance and operations of certain aspects of our business, which, if terminated, could result in a shortage of a readily available workforce to provide these services. If any of these agreements or arrangements is terminated for any reason, we may face difficulty finding a qualified replacement work force to provide such services, which could have an adverse effect on our ability to carry on our business and on our results of operations.

Hazards associated with high-voltage electricity transmission may result in suspension of our operations or the imposition of civil or criminal penalties.

Our operations are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, inclement weather, natural disasters, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. The hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations and the imposition of civil or criminal penalties. AEPTCo maintains property and casualty insurance, but we are not fully insured against all potential hazards incident to our business, such as damage to poles, towers and lines or losses caused by outages.

We are subject to environmental regulations and to laws that can give rise to substantial liabilities.

We are subject to federal, state and local environmental laws and regulations, which impose requirements to minimize environmental and other impacts from our construction activities, limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities relating to investigation and remediation of contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes were treated or disposed of in accordance with historic standards, as well as properties we currently own or operate. Such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire share.

Failure to comply with environmental laws and regulations applicable to us could result in civil or criminal penalties and remediation costs. Our assets and operations also involve the use of materials classified as hazardous, toxic or otherwise dangerous. Some of our facilities and properties are located near environmentally sensitive areas such as wetlands and habitats of endangered or threatened species. Compliance with these laws and regulations, and liabilities concerning contamination or hazardous materials, may adversely affect our costs and, therefore, our business, financial condition and results of operations.

We are subject to various regulatory requirements, including reliability standards; contract filing requirements; reporting, recordkeeping and accounting requirements; and transaction approval requirements.

Under federal law, owners and operators of the bulk power transmission system are subject to mandatory reliability standards, including both operational and cybersecurity standards, promulgated by the North American Electric Reliability Corporation ("NERC") and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable.

Our subsidiaries must comply with FERC requirements for approval of certain transactions; reporting, recordkeeping and accounting requirements; and for filing contracts related to the provision of jurisdictional services. Under FERC policy, failure to file jurisdictional agreements on a timely basis may result in foregoing the time value of revenues collected under the agreement, but not to the point where a loss would be incurred. The failure to obtain timely approval of transactions or to comply with applicable reporting, recordkeeping or accounting requirements could subject us to penalties that could have a material adverse effect on our financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, cyberattacks, natural disasters, severe weather and other catastrophic events may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, cyberattacks, natural disasters, severe weather and other catastrophic events may negatively affect our business, financial condition and cash flows in unpredictable ways, such as increased security measures and disruptions of markets. Energy related assets, including, for example, our transmission facilities and the generation and distribution facilities that we interconnect with, may be at risk of acts of war, terrorist attacks and cyberattacks, as well as natural disasters, severe weather and other catastrophic events. In addition to any physical damage caused by such events, cyberattacks targeting our information systems could impair our records, networks, systems and programs, or transmit viruses to other systems. Such events or the threat of such events may increase costs associated with heightened security requirements. In addition, such events or threats may have a material effect on the economy in general and could result in a decline in energy consumption, which may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Recent changes in federal income tax policy may adversely affect cash flows, as well as credit ratings.

Recently enacted United States federal income tax legislation significantly changed the Internal Revenue Code, including taxation of corporations, by, among other things, reducing the federal corporate income tax rate, limiting interest deductions, and altering the expensing of capital expenditures. The legislation is unclear in certain respects and will require interpretations and implementing regulations by the Internal Revenue Service ("IRS"), as well as state income tax authorities, and the legislation could be subject to potential amendments and technical corrections, any of which could lessen or increase certain adverse impacts of the legislation. In addition, the regulatory treatment of the impacts of this legislation will be subject to the discretion of the FERC.

Although it is unclear when or how capital markets, credit rating agencies or the FERC may respond to this legislation, Management expects that certain financial metrics used by credit rating agencies, such as funds from operations-to-debt percentage, could be negatively impacted. Management expects that the State Transcos will return the tax benefits to customers, either through decreasing rates, increasing the amortization of regulatory assets, accelerating depreciation or offsetting other rate increases. The amount and the timing of any payments of tax benefits to be returned to customers will ultimately be determined by the FERC.

Management's analysis and interpretation of this legislation is preliminary and ongoing. Based on Management's current evaluation, limitations on interest deductions are not expected to be significant. Any amendments to the legislation or interpretations or implementing regulations by the IRS contrary to Management's interpretation of the legislation could limit the ability to deduct the interest on some of the Company's outstanding debt.

There may be other material adverse effects resulting from the legislation that have not yet been identified. If Management is unable to successfully take actions to manage any adverse impacts of the new tax legislation, or if additional interpretations, regulations, amendments or technical corrections exacerbate the adverse impacts of the legislation, the legislation could have an adverse effect on the Company's financial condition, results of operations and cash flows and on the value of investments in debt securities and common stock. Any negative actions by credit rating agencies may make it more costly to issue future debt securities and could increase borrowing costs under existing credit facilities. For additional information, see Note 4 - Rate Matters and Note 12 - Income Taxes, of the Notes to our audited financial statements included elsewhere in this prospectus.

Risks Relating to Our Corporate and Financial Structure

We are a holding company with no operations, and unless we receive dividends or other payments from our subsidiaries, we may be unable to fulfill our other cash obligations.

As a holding company with no business operations, our material assets consist primarily of the stock interests in the State Transcos. Our only sources of cash to pay interest on our indebtedness are dividends and other payments received by us from time to time from the State Transcos, capital contributions from AEP, proceeds raised from the sale of our debt and borrowings. Each of the State Transcos, however, is legally distinct from us and has no obligation, contingent or otherwise, to make funds available to us (apart from payment obligations in connection with loans that we have made to the State Transcos). The ability of each of our State Transcos to pay dividends and make other payments to us is subject to, among other things, the availability of funds, after taking into account capital expenditure requirements, the terms of its indebtedness, applicable state laws and regulations of the FERC.

AEPTCo is the sole obligor of the Exchange Notes and the State Transcos will not guarantee AEPTCo's obligations under the Exchange Notes. Although certain debt covenants limit external debt at the subsidiary level, the Exchange Notes will be structurally subordinated to the debt and other liabilities of the State Transcos and the assets of the State Transcos may not be available to make payments on the Exchange Notes.

None of the State Transcos will guarantee AEPTCo's obligations under the Exchange Notes. Although certain debt covenants limit external debt at the subsidiary level, the Exchange Notes are structurally subordinated to all of the debt and other liabilities of the State Transcos (other than debt owed to AEPTCo, "Parent Debt"). For a description of such covenants, see "DESCRIPTION OF THE EXCHANGE NOTES - Certain Covenants" and Note 14, to our

audited financial statements and related notes included elsewhere in this prospectus. In the event that any of the State Transcos becomes insolvent, liquidate, reorganize, dissolve or otherwise wind up, holders of that State Transco's debt and its trade creditors generally will be entitled to payment on their claims from the assets of that State Transco before any of those assets are made available to AEPTCo. Consequently, the claims of holders of the Exchange Notes will be effectively subordinated to all of the debt and other liabilities of the State Transcos, including trade payables.

As of February 28, 2018, the State Transcos had an aggregate of $238 million in debt outstanding, other than Parent Debt.

Although the Exchange Notes are designated as "senior" your right to receive payment on the Exchange Notes will be unsecured and effectively subordinated to any future secured debt of AEPTCo, to the extent of the value of the collateral therefor.

The Exchange Notes will be general senior unsecured obligations and therefor will be effectively subordinated to AEPTCo's future secured indebtedness. As of March 1, 2018, AEPTCo had no secured indebtedness outstanding. Although the Indenture places some limitations on our ability to create liens securing indebtedness, there are significant exceptions to these limitations that would allow us to secure indebtedness without equally and ratably securing the Exchange Notes. If AEPTCo were to incur secured indebtedness and if AEPTCo defaulted on the Exchange Notes or certain other indebtedness or became bankrupt, liquidated or reorganized, any secured creditor could use the value of the collateral securing that debt to satisfy their secured indebtedness before you would receive any payment on the Exchange Notes, unless the Exchange Notes were similarly secured as described in "DESCRIPTION OF THE EXCHANGE NOTES - Certain Covenants - Limitation on Liens" herein. If the value of such collateral is not sufficient to pay any secured indebtedness in full, AEPTCo's secured creditors would share the value of AEPTCo's other assets, if any, with you and the holders of other claims against AEPTCo which rank equally with the Exchange Notes.

AEPTCo could enter into various transactions that could increase the amount of its outstanding indebtedness, or adversely affect its capital structure or credit ratings, or otherwise adversely affect the holders of the Exchange Notes.

The terms of the Exchange Notes will not prevent AEPTCo from entering into a variety of acquisition, refinancing, recapitalization or other highly-leveraged transactions. As a result, AEPTCo may enter into a transaction even though the transaction could increase the total amount of its outstanding indebtedness, adversely affect its capital structure or credit ratings or otherwise adversely affect the holders of the Exchange Notes.

As of February 28, 2018, AEPTCo had approximately $2.8 billion of indebtedness outstanding.

Certain provisions in our debt instruments limit our financial and operating flexibility.

Our outstanding debt instruments contain numerous financial and operating covenants that place significant restrictions on, among other things, our ability to:

- incur Consolidated Priority Debt;
- create liens;
- dispose of certain assets;
- enter into certain lines of business;
- engage in transactions with affiliates;
- engage in mergers and consolidations

Our outstanding debt instruments also require us to meet certain financial ratios, such as maintaining certain debt to capitalization ratios. Our ability to comply with these and other requirements and restrictions may be affected by changes in economic or business conditions, results of operations or other events beyond our control. A failure to comply with the obligations contained in any of our debt instruments could result in acceleration of certain of our outstanding debt and the acceleration of debt under other instruments evidencing indebtedness that may contain cross-acceleration provisions.

Certain covenants with respect to the Exchange Notes and our outstanding indebtedness are described under “DESCRIPTION OF THE EXCHANGE NOTES - Certain Covenants” and Note 14, to our audited financial statements and related notes included elsewhere in this prospectus.

Adverse changes in our credit ratings may negatively affect us.

Our ability to access capital markets is important to our ability to operate our business. Increased scrutiny of the energy industry and the impact of regulation, as well as changes in our financial performance and unfavorable conditions in the capital markets could result in credit agencies reexamining our credit ratings. A downgrade in our credit ratings could restrict or discontinue our ability to access capital markets at attractive rates and increase our borrowing costs.

We are subject to control by AEP.

We are an indirect wholly-owned subsidiary of AEP and, therefore, AEP ultimately controls the decision of all matters submitted for shareholder approval. In circumstances involving a conflict of interest between AEP, on the one hand, and our creditors, on the other, AEP could exercise this power to the detriment of our creditors, including holders of the Exchange Notes.

Risks Related to the Exchange Offers

There may be adverse consequences if you do not exchange your Outstanding Notes.

If you do not exchange your Outstanding Notes for Exchange Notes in the Exchange Offers, you will continue to be subject to restrictions on transfer of your Outstanding Notes as set forth in the offering memorandum distributed in connection with the private offering of the Outstanding Notes. In general, the Outstanding Notes may not be offered or sold unless they are registered or exempt from registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreement, we do not intend to register resales of the Outstanding Notes under the Securities Act. You should refer to “Prospectus Summary-The Exchange Offers” and “The Exchange Offers” for information about how to tender your Outstanding Notes.

The tender of Outstanding Notes under the Exchange Offers will reduce the outstanding amount of the Outstanding Notes, which may have an adverse effect upon, and increase the volatility of, the market prices of the Outstanding Notes due to a reduction in liquidity.

Your ability to transfer the Exchange Notes may be limited if there is no active trading market, and there is no assurance that any active trading market will develop for the Exchange Notes.

We are offering the Exchange Notes to the holders of the Outstanding Notes. We do not intend to list the Exchange Notes on any securities exchange. There is currently no established market for the Exchange Notes. If no active trading market develops, you may not be able to resell your Exchange Notes at their fair market value or at all. Future trading prices of the Exchange Notes will depend on many factors including, among other things, prevailing interest rates, our operating results and the market for similar securities. No assurance can be given as to the liquidity of or trading market for the Exchange Notes.

Certain persons who participate in the Exchange Offers must deliver a prospectus in connection with resales of the Exchange Notes.

Based on interpretations of the staff of the SEC contained in Exxon Capital Holdings Corp., SEC no-action letter (available May 13, 1988), Morgan Stanley & Co. Inc., SEC no-action letter (available June 5, 1991) and Shearman & Sterling, SEC no-action letter (available July 2, 1993), we believe that you may offer for resale, resell or otherwise transfer the Exchange Notes without compliance with the registration and prospectus delivery requirements of the Securities Act. We cannot guarantee that the SEC would make a similar decision about our Exchange Offers. If our

belief is wrong, or if you cannot truthfully make the representations mentioned above, and you transfer any Exchange Note issued to you in the Exchange Offers without meeting the registration and prospectus delivery requirements of the Securities Act, or without an exemption from such requirements, you could incur liability under the Securities Act. Additionally, in some instances described in this prospectus under “Plan of Distribution,” certain holders of Exchange Notes will remain obligated to comply with the registration and prospectus delivery requirements of the Securities Act to transfer the Exchange Notes. If such a holder transfers any Exchange Notes without delivering a prospectus meeting the requirements of the Securities Act or without an applicable exemption from registration under the Securities Act, such a holder may incur liability under the Securities Act. We do not and will not assume, or indemnify such a holder against, this liability.

Risks Related to the Exchange Notes

The following risks apply to the Outstanding Notes and will apply equally to the Exchange Notes.

If the ratings of the Exchange Notes are lowered or withdrawn, the market value of the Exchange Notes could decrease.

A rating is not a recommendation to purchase, hold or sell the Exchange Notes, inasmuch as the rating does not comment as to market price or suitability for a particular investor. The ratings of the Exchange Notes address the rating agencies’ views as to the likelihood of the timely payment of interest and the ultimate repayment of principal of the Exchange Notes pursuant to their respective terms. There is no assurance that a rating will remain for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if in their judgment circumstances in the future so warrant. In the event that any of the ratings initially assigned to the Exchange Notes is subsequently lowered or withdrawn for any reason, the market price of the Exchange Notes may be adversely affected.

FORWARD-LOOKING STATEMENTS

We use forward-looking statements in this prospectus. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of our management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as “believe,” “expect,” “anticipate,” “plan,” “estimate” or similar expressions. Such statements speak only as of the date they are made, and we undertake no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in the Company’s service territory.
- 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.
- Electric load and customer growth.
- Weather conditions, including storms and drought conditions.
- 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.
- New legislation, litigation and government regulation.
- Regulatory decisions, including rate or other recovery of new investments in transmission service and excess accumulated deferred income taxes.
- The ability to constrain operation and maintenance costs.
- Changes in utility regulation and the allocation of costs within regional transmission organizations, including Pennsylvania-New Jersey-Maryland regional transmission organization (“PJM”) and Southwest Power Pool regional transmission organization (“SPP”).
- Actions of rating agencies, including changes in our ratings.
- 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.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. For additional details regarding these and other risks and uncertainties, see “RISK FACTORS” in this prospectus.

USE OF PROCEEDS

We will not receive any cash proceeds from the issuance of the Exchange Notes pursuant to the Exchange Offers. In consideration for issuing the Exchange Notes as contemplated in this prospectus, we will receive in exchange a like principal amount of Outstanding Notes, the terms of which are identical in all material respects to the Exchange Notes of the related series, except that the Exchange Notes will not contain terms with respect to transfer restrictions, registration rights and additional interest for failure to observe certain obligations in the registration rights agreement. The Outstanding Notes surrendered in exchange for the Exchange Notes will be retired and cancelled, and will not be reissued. Accordingly, the issuance of the Exchange Notes will not result in any increase in our outstanding debt or the receipt of any additional proceeds.

CAPITALIZATION

The following table sets forth our unaudited capitalization as of December 31, 2017.

You should read the data set forth below in conjunction with "USE OF PROCEEDS," "SELECTED FINANCIAL DATA," "MANAGEMENT'S DISCUSSION AND ANALYSIS," and our audited consolidated financial statements as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015, and related notes included elsewhere in this prospectus.

The Outstanding Notes that are surrendered in exchange for the Exchange Notes will be retired and cancelled and cannot be reissued. As a result, the issuance of the Exchange Notes will not result in any change in our capitalization.

	As of December 31, 2017	
	(in millions)	
Long-Term Debt and Advances from Affiliates		
Long-Term Debt, including amounts due within one year	$	2,550
Advances from Affiliates (a)		16
Total Long-Term Debt and Advances from Affiliates		2,566
Total Equity		2,605
Total Capitalization	$	5,171

(a) Represents Advances from AEP's Utility Money Pool.

SELECTED FINANCIAL DATA

The selected financial data presented below for the years ended December 31, 2014 and 2013 and as of December 31, 2015, 2014 and 2013 have been derived from AEPTCo's audited consolidated financial statements which are not included elsewhere in this prospectus. The selected financial data for the years ended December 31, 2017, 2016 and 2015 and as of December 31, 2017 and 2016 have been derived from AEPTCo's audited consolidated financial statements which are included elsewhere in this prospectus. Historical results are not necessarily indicative of future results.

You should read the data set forth below in conjunction with "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" and AEPTCo's audited consolidated financial statements and related notes included elsewhere in this prospectus.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(in millions)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 723.2	$ 478.0	$ 310.2	$ 182.2	$ 77.7
Operating Income	$ 447.8	$ 280.1	$ 174.4	$ 113.8	$ 41.1
Income Before Income Tax Expense	$ 433.3	$ 286.8	$ 192.9	$ 137.3	$ 60.8

	2017	2016	2015	2014	2013
Net Income	$ 286.1	$ 192.7	$ 132.9	$ 101.2	$ 48.7

	As of December 31,				
	2017	2016	2015	2014	2013
	(in millions)				
BALANCE SHEETS DATA					
Total Transmission Property	$ 6,780.2	$ 5,054.2	$ 3,749.8	$ 2,620.4	$ 1,636.1
Accumulated Depreciation and Amortization	170.4	99.6	51.7	24.5	9.6
Total Transmission Property – Net	$ 6,609.8	$ 4,954.6	$ 3,698.1	$ 2,595.9	$ 1,626.5
Total Assets	$ 7,068.1	$ 5,349.8	$ 4,156.4	$ 2,929.8	$ 1,748.8
Total Member's Equity	$ 2,605.3	$ 1,957.6	$ 1,552.9	$ 1,140.9	$ 692.2
Long-term Debt (a)	$ 2,550.4	$ 1,932.0	$ 1,544.4	$ 1,094.9	$ 616.9

(a) Includes portion due within one year.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis by management focuses on those factors that had a material effect on AEPTCo's results of operations and financial condition during the periods presented and should be read in connection with AEPTCo's audited consolidated financial statements and related notes included elsewhere in this prospectus. The discussion contains certain forward-looking statements that involve risk and uncertainties. See "FORWARD LOOKING STATEMENTS" and "RISK FACTORS."

EXECUTIVE OVERVIEW

Company Overview

AEP Transmission Company, LLC ("AEPTCo" or the "Company") is a holding company for seven FERC regulated transmission-only electric utilities. AEPTCo is an indirect wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP").

AEPTCo's seven wholly-owned public utility companies are (collectively referred to herein as the "State Transcos"):

- AEP Appalachian Transmission Company, Inc. ("APTCo"),
- AEP Indiana Michigan Transmission Company, Inc. ("IMTCo"),
- AEP Kentucky Transmission Company, Inc. ("KTCo"),
- AEP Ohio Transmission Company, Inc. ("OHTCo"),
- AEP West Virginia Transmission Company, Inc. ("WVTCo"),
- AEP Oklahoma Transmission Company, Inc. ("OKTCo") and
- AEP Southwestern Transmission Company, Inc. ("SWTCo").

AEPTCo's business activities are the development, construction and operation of transmission facilities through investments in the State Transcos. The State Transcos have assets in service or under construction across two RTOs and in seven states, with additional states pending approval. As of December 31, 2017, the State Transcos had $5.5 billion of transmission assets in-service with plans to construct approximately $4.3 billion of additional transmission assets through 2020. AEPTCo anticipates the need for additional investment in transmission infrastructure within PJM and SPP to maintain the required level of grid reliability, resiliency, security and efficiency and to address an aging transmission infrastructure. AEPTCo also foresees the need to construct additional transmission facilities based on changes in generating resources, such as wind or solar projects, generation additions or retirements, and additional new customer interconnections. AEPTCo will continue its investment to enhance physical and cyber security of its assets, and is also investing in improving the telecommunication network that supports the operation and control of the grid. AEPTCo's fundamental obligation to meet state, federal, regulatory and industry standards will continue to drive transmission investment.

Federal Tax Reform

In December 2017, legislation referred to as Tax Reform was signed into law. The majority of the provisions in the new legislation are effective for taxable years beginning after December 31, 2017. Tax Reform includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and also includes provisions specific to regulated public utilities. The more significant changes that affect AEPTCo include the reduction in the corporate federal income tax rate from 35% to 21%, and several technical provisions including, among others, limiting the utilization of net operating losses arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, eliminate bonus depreciation for certain property acquired after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

Changes in the Code due to Tax Reform had a material impact on AEPTCo's 2017 financial statements. As a result of Tax Reform, AEPTCo's deferred tax assets and liabilities were re-measured using the newly enacted tax rate of 21% in December 2017. This re-measurement resulted in a significant reduction in AEPTCo's net accumulated deferred income tax liability. With respect to AEPTCo's regulated operations, the reduction of the net accumulated deferred income tax liability was primarily offset by a corresponding decrease in income tax related regulatory assets and an increase in income tax related regulatory liabilities because the benefit of the lower federal tax rate is expected to be provided to customers. For AEPTCo's unregulated operations, the re-measurement of deferred taxes arising from those operations was recorded as an adjustment to income tax expense.

As a result of Tax Reform, AEPTCo reflected a decrease in Deferred Income Tax Liabilities of $559 million, an increase in income tax related Regulatory Liabilities of $493 million, a decrease in income tax related Regulatory Assets of $67 million and an increase to Income Tax Expense of $1 million.

Regulatory Treatment

As a result of Tax Reform, AEPTCo recognized a regulatory liability for approximately $389 million of excess accumulated deferred income taxes (Excess ADIT), as well as an incremental liability of $104 million to reflect the $389 million Excess ADIT on a pre-tax basis. The Excess ADIT is reflected on a pre-tax basis to appropriately contemplate future tax consequences in the periods when the regulatory liability is settled. Approximately $409 million of the Excess ADIT relates to temporary differences associated with depreciable property. The Tax Reform legislation includes certain rate normalization requirements that stipulate how the portion of the total Excess ADIT that is related to certain depreciable property must be passed back to customers. Specifically, for AEP's regulated public utilities that are subject to those rate normalization requirements, Excess ADIT resulting from the reduction of the corporate tax rate with respect to prior depreciation or recovery deductions on property will be normalized using the average rate assumption method. As a result, once the amortization of this Excess ADIT is reflected in rates, customers will receive the benefits over the remaining weighted average useful life of the applicable property.

For the remaining $(20) million of Excess ADIT, AEPTCo expects to continue working with the FERC to determine the appropriate mechanism and time period to amortize the Excess ADIT.

AEPTCo expects the mechanism and time period to provide the benefits of Tax Reform to customers will vary by jurisdiction and is not expected to have a material impact on future net income. However, AEPTCo anticipates a decrease in future cash flows primarily due to the elimination of bonus depreciation, the reduction in the federal tax rate from 35% to 21% and the flow back of Excess ADIT. Further, AEPTCo expects that access to capital markets will be sufficient to satisfy any liquidity needs that result from any such decrease in future cash flows.

FERC Transmission Complaint - AEP's PJM Participants

In October 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's eastern transmission subsidiaries, including AEPTCo, in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, the AEP eastern transmission companies, including AEPTCo, and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC, the settlement agreement (a) establishes a base ROE for AEP's eastern transmission subsidiaries of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires the AEP eastern transmission companies to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, to be credited to customer bills in the second quarter of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's eastern transmission subsidiaries also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate from 35% to 21%, effective January 1, 2018 and provides for the amortization of the portion of the excess accumulated deferred income taxes, not subject to the normalization method of accounting, ratably over a ten year period through credits to the federal income tax expense component of the revenue requirement.

Management believes AEPTCo's financial statements adequately address the impact of the settlement agreement. If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition. A decision from the FERC is pending.

Modifications to AEP's PJM Transmission Rates

In November 2016, AEP's eastern transmission subsidiaries, including AEPTCo, filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, AEP's eastern transmission subsidiaries filed an uncontested settlement agreement with the FERC resolving all outstanding issues. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's SPP Participants

In June 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's western transmission subsidiaries, including AEPTCo, in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's SPP Transmission Rates

In October 2017, AEP's western transmission subsidiaries, including AEPTCo, filed an application at the FERC to modify the

SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected 2018 calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

RESULTS OF OPERATIONS

The table below summarizes the significant components of AEPTCo's net income for the years ended December 31, 2017, 2016 and 2015.

	Years Ended December 31,		
	2017	2016	2015
		(in millions)	
Transmission Revenues	$ 723.2	$ 478.0	$ 310.2
Other Operation and Maintenance	68.6	43.7	27.4
Depreciation and Amortization	97.1	65.9	42.4
Taxes Other Than Income Taxes	109.7	88.3	66.0
Operating Income	447.8	280.1	174.4
Interest Income	1.2	0.4	0.1
Allowance for Equity Funds Used During Construction	52.3	52.3	53.0
Interest Expense	(68.0)	(46.0)	(34.6)
Income Before Income Tax Expense	433.3	286.8	192.9
Income Tax Expense	147.2	94.1	60.0
Net Income	$ 286.1	$ 192.7	$ 132.9

Summary of Investment in Transmission Assets for AEPTCo

	As of December 31,		
	2017	2016	2015
		(in millions)	
Plant In Service	$ 5,467.5	$ 4,072.9	$ 2,815.6
CWIP	1,312.7	981.3	934.2
Accumulated Depreciation	170.4	99.6	51.7
Total Transmission Property, Net	$ 6,609.8	$ 4,954.6	$ 3,698.1

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Net Income
(in millions)

Year Ended December 31, 2016	$	192.7
Changes in Transmission Revenues:		
Transmission Revenues		245.2
Total Change in Transmission Revenues		245.2
Changes in Expenses and Other:		
Other Operation and Maintenance		(24.9)
Depreciation and Amortization		(31.2)
Taxes Other Than Income Taxes		(21.4)
Interest Income		0.8
Interest Expense		(22.0)
Total Change in Expenses and Other		(98.7)
Income Tax Expense		(53.1)
Year Ended December 31, 2017	$	286.1

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 $245 million primarily due to:
  - A $237 million increase in formula rates driven by the favorable impact of the modification of the PJM OATT formula combined with an increase driven by continued investments in transmission assets.
  - A $7 million increase due to rental revenue related to various AEPTCo facilities.

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

- **Other Operation and Maintenance** expenses increased $25 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $31 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $21 million primarily due to increased property taxes as a result of additional transmission investment.
- **Interest Expense** increased $22 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $53 million primarily due to an increase in pretax book income.

2016 Compared to 2015

Reconciliation of Year Ended December 31, 2015 to Year Ended December 31, 2016
Net Income
(in millions)

Year Ended December 31, 2015	$	132.9
Changes in Transmission Revenues:		
Transmission Revenues		167.8
Total Change in Transmission Revenues		167.8

Changes in Expenses and Other:		
Other Operation and Maintenance		(16.3)
Depreciation and Amortization		(23.5)
Taxes Other Than Income Taxes		(22.3)
Interest Income - Affiliated		0.3
Allowance for Equity Funds Used During Construction		(0.7)
Interest Expense		(11.4)
Total Change in Expenses and Other		(73.9)
Income Tax Expense		(34.1)
Year Ended December 31, 2016	$	192.7

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 $168 million primarily due to the following:
  - A $140 million increase due to formula rate increases driven by continued investment in transmission assets and the related increases in recoverable operating expenses.
  - A $28 million increase due to annual formula rate true-up adjustments.

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

- **Other Operation and Maintenance** expenses increased $16 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $24 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $22 million primarily due to increased property taxes as a result of additional transmission investment.
- **Interest Expense** increased $11 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $34 million primarily due to an increase in pretax book income.

FINANCIAL CONDITION

AEPTCo 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

	December 31,					
	2017			2016		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$	2,550.4	49.3%	$	1,932.0	49.6%
Advances from Affiliates		15.7	0.3%		4.1	0.1%
Total Debt		2,566.1	49.6%		1,936.1	49.7%
Member's Equity		2,605.3	50.4%		1,957.6	50.3%
Total Debt and Equity Capitalization	$	5,171.4	100.0%	$	3,893.7	100.0%

AEPTCo's ratio of debt-to-total capital decreased primarily due to an increase in member's equity related to capital contributions from member and net income, partially offset by an increase in long-term debt due to an increase in construction expenditures.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEPTCo's financial stability. AEPTCo has access to AEP's liquidity through AEP's corporate borrowing program. AEP uses its corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries, including AEPTCo Parent and the State Transcos. These short-term borrowings are generally used by AEPTCo to fund working capital needs, property acquisitions and construction until long-term funding is arranged. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries and a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries. APTCo, IMTCo, KTCo, OHTCo, OKTCo and WVTCo have been approved to participate in the Utility Money Pool. In addition, for AEP subsidiaries including AEPTCo Parent and SWTCo, that are not participants in either money pool due to regulatory or operational reasons, the corporate borrowing program funds the short-term debt requirements of those subsidiaries as direct borrowers. The corporate borrowing program is backed by AEP's commercial paper program and corporate credit facilities. Management believes AEPTCo has adequate liquidity under the AEP's corporate borrowing program.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2017, AEP had a $3 billion revolving credit facility commitment to support its operations. AEPTCo does not maintain separate credit facilities. During 2017, the maximum amount of commercial paper AEP had outstanding was $1.6 billion. The weighted-average interest rate for AEP's commercial paper during 2017 was 1.25%. As of December 31, 2017, AEP's available liquidity was approximately $2.3 billion as illustrated in the table below:

	Amount		Maturity
	(in millions)		
Commercial Paper Backup:			
Revolving Credit Facility	$	3,000.0	June 2021
Cash and Cash Equivalents		214.6	
Total Liquidity Sources		3,214.6	
Less: AEP Commercial Paper Outstanding		898.6	
Net Available Liquidity	$	2,316.0	

Additional liquidity is available to AEPTCo from cash from operations, the issuance of long-term debt as well as equity contributions from AEP. Management is committed to maintaining adequate liquidity.

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 four uncommitted facilities totaling $345 million. In October 2017, a $100 million uncommitted facility expired. As of December 31, 2017, the maximum future payment for letters of credit issued under the uncommitted facilities was $104 million with maturities ranging from January 2018 to December 2018. As of December 31, 2017 AEPTCo had no letters of credit outstanding under these facilities.

Financing Plan

AEPTCo plans to refinance long-term debt as it becomes due and issue incremental debt, as needed, to support future capital expenditure plans.

Debt Covenants and Borrowing Limitations

AEPTCo's long-term debt agreements and AEP's credit agreements contain certain covenants and require AEPTCo and AEP 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 AEPTCo's long-term debt agreements and AEP's credit agreements. Debt as defined in AEP's credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2017, this contractually-defined percentage for AEP and AEPTCo was 53.5% and 49.6%, respectively. AEPTCo also has a priority debt limitation on external debt under its long-term debt agreements that limits such debt incurred by AEPTCo's State Transco subsidiaries to 10% of AEPTCo's tangible net assets. The method for calculating the priority debt limitation is contractually defined in AEPTCo's long-term debt obligations. Nonperformance under these covenants could result in an event of default under these credit agreements. In addition, subject to certain exceptions, AEPTCo Parent has covenanted that it will not incur debt secured by a lien unless its other indebtedness is similarly secured. As of December 31, 2017, AEP and AEPTCo were in compliance with all of the covenants contained in their long-term debt and credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, including AEPTCo, 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.

The AEP 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.

For a further discussion of AEPTCo's debt covenants, see Note 14 - Financing Activities in the 2017 Annual Report, included elsewhere in this prospectus.

Credit Ratings

AEPTCo does not have any long-term debt or credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade.

Capital Contributions Subsequent to Year-End

In January 2018 AEP Transmission Holdco made a capital contribution of $65 million to AEPTCo Parent. Consequently, AEPTCo Parent made capital contributions of $35 million, $20 million and $10 million to IMTCo, OHTCo and OKTCo, respectively.

CASH FLOW

AEPTCo relies primarily on cash flows from operations and debt issuances to fund its liquidity and investing activities. AEPTCo's investing and capital requirements are primarily capital expenditures and repaying advances received from affiliates. AEPTCo uses advances from affiliates, in addition to capital contributions, 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.

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Cash and Cash Equivalents at Beginning of Period	$ —	$ —	$ —
Net Cash Flows from Operating Activities	604.8	548.9	199.4
Net Cash Flows Used for Investing Activities	(1,595.6)	(1,135.0)	(940.1)
Net Cash Flows from Financing Activities	990.8	586.1	740.7
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —

Operating Activities

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net Income	$ 286.1	$ 192.7	$ 132.9
Non-Cash Adjustments to Net Income (a)	317.6	236.7	172.6
Property Taxes	(15.6)	(15.3)	(25.6)
Change in Other Noncurrent Assets	9.8	(2.8)	1.8
Change in Other Noncurrent Liabilities	27.3	4.4	0.6
Change in Certain Components of Working Capital	(20.4)	133.2	(82.9)
Net Cash Flows from Operating Activities	$ 604.8	$ 548.9	$ 199.4

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, and Allowance for Equity Funds Used During Construction.

2017 Compared to 2016

Net Cash Flows from Operating Activities increased by $56 million primarily due to the following:

- A $174 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $23 million increase in cash from Changes in Other Noncurrent Liabilities primarily due to an increase in Accumulated Provisions for Rate Refunds.

This increase in cash was partially offset by:

- A $153 million decrease in cash from Changes in Certain Components of Working Capital. This decrease in cash is primarily due to bonus tax depreciation, and an increase in property tax payments due to additional transmission investments. See Note 12- Income Taxes in the 2017 Annual Report, included elsewhere in this prospectus, for additional information.

2016 Compared to 2015

Net Cash Flows from Operating Activities increased by $350 million primarily due to the following:

- A $216 million increase in cash from Changes in Certain Components of Working Capital. This increase in cash is primarily due to bonus tax depreciation, partially offset by an increase in property tax payments due to additional transmission investments. See Note 12- Income Taxes in the 2017 Annual Report, included elsewhere in this prospectus, for additional information.
- A $124 million increase in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for additional information.

Investing Activities

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Construction Expenditures	$ (1,513.4)	$ (1,159.5)	$ (1,007.8)
Change in Advances to Affiliates, Net	(79.2)	29.0	65.4
Acquisitions of Assets	(9.1)	(6.5)	(1.1)
Other	6.1	2.0	3.4
Net Cash Flows Used for Investing Activities	$ (1,595.6)	$ (1,135.0)	$ (940.1)

2017 Compared to 2016

Net Cash Flows Used for Investing Activities increased by $461 million primarily due to the following:

- A $354 million decrease in cash due to increased construction expenditures supporting the continued investment in transmission assets.
- A $108 million decrease in cash due to increased advances to affiliates.

2016 Compared to 2015

Net Cash Flows Used for Investing Activities increased by $195 million primarily due to the following:

- A $152 million decrease in cash due to increased construction expenditures supporting the continued investment in transmission assets.
- A $36 million decrease in cash due to decreased repayments received from advances to affiliates.

Financing Activities

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Capital Contributions from Member	$ 361.6	$ 212.0	$ 279.0
Issuance/Retirement of Debt, Net	617.6	386.9	449.0
Change in Advances from Affiliates, Net	11.6	(12.8)	12.7
Net Cash Flows from Financing Activities	$ 990.8	$ 586.1	$ 740.7

2017 Compared to 2016

Net Cash Flows from Financing Activities increased by $405 million primarily due to the following:

- A $300 million increase in cash due to decreased retirements of long-term debt. See Note 14 - Financing Activities in the 2017 Annual Report, included elsewhere in this prospectus, for additional information.
- A $150 million increase in cash due to increased Capital Contributions from Member.
- A $24 million increase in cash due to increased proceeds received from advances from affiliates.

These increases in cash were partially offset by:

- A $69 million decrease in cash due to decreased issuances of long-term debt. See Note 14 - Financing Activities in the 2017 Annual Report, included elsewhere in this prospectus, for additional information.

2016 Compared to 2015

Net Cash Flows from Financing Activities decreased by $155 million primarily due to the following:

- A $300 million decrease in cash due to increased retirements of long-term debt. See Note 14 - Financing Activities in the 2017 Annual Report, included elsewhere in this prospectus, for additional information.
- A $67 million decrease in cash due to reduced Capital Contributions from Member.
- A $26 million decrease in cash due to repayments of advances from affiliates.

These decreases were partially offset by:

- A $238 million increase in cash due to increased issuances of long-term debt. See Note 14 - Financing Activities in the 2017 Annual Report, included elsewhere in this prospectus, for additional information.

BUDGETED CONSTRUCTION EXPENDITURES

Management forecasts approximately $1.5 billion of construction expenditures in 2018. For 2019 and 2020 combined, management forecasts construction expenditures of approximately $2.7 billion. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these construction expenditures through cash flows from operations and financing activities. AEPTCo Parent and SWTCo can borrow directly from AEP to meet short-term borrowing needs. APTCo, IMTCo, KTCo, OHTCo, OKTCo and WVTCo have been approved to participate in the Utility Money Pool to finance their short-term borrowing needs until long-term funding is arranged.

OFF-BALANCE SHEET ARRANGEMENTS

AEPTCo's current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that AEPTCo enters in the normal course of business. As of December 31, 2017 and 2016, AEPTCo had no off-balance sheet arrangements.

CONTRACTUAL OBLIGATION INFORMATION

AEPTCo's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes to AEPTCo's audited consolidated financial statements, included elsewhere in this prospectus. The following table summarizes AEPTCo's contractual cash obligations as of December 31, 2017:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Advances from Affiliates (a)	$ 15.7	$ —	$ —	$ —	$ 15.7
Interest on Fixed Rate Portion of Long-term Debt (b)	102.5	193.5	189.6	1,479.8	1,965.4
Fixed Rate Portion of Long-term Debt (c)	50.0	85.0	154.0	2,286.0	2,575.0
Capital Lease Obligations (d)	0.1	0.1	—	—	0.2
Noncancelable Operating Leases (d)	1.7	2.3	0.4	—	4.4
Construction Contracts for Capital Assets (e)	487.1	843.8	—	—	1,330.9
Total	$ 657.1	$ 1,124.7	$ 344.0	$ 3,765.8	$ 5,891.6

(a) Represents principal only, excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14 in the 2017 Annual Reports, included elsewhere in this prospectus. Represents principal only, excluding interest and debt issuance costs.
(d) See Note 13 in the 2017 Annual Report, included elsewhere in this prospectus.
(e) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

SIGNIFICANT TAX LEGISLATION

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit.

These enacted provisions had no material impact on net income or financial condition but did have a favorable impact on cash flows in 2015, 2016 and 2017.

Federal Tax Reform

In December 2017, legislation referred to as Tax Reform was signed into law. The majority of the provisions in the new legislation are effective for taxable years beginning after December 31, 2017. Tax Reform includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and also includes provisions specific to regulated public utilities. The more significant changes that affect AEPTCo include the reduction in the corporate federal income tax rate from 35% to 21%, and several technical provisions including, among others, limiting the utilization of net operating losses arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, eliminate bonus depreciation for certain property acquired after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

Changes in the Code due to Tax Reform had a material impact on AEPTCo's 2017 financial statements. See "Federal Tax Reform" section of Note 12 in the 2017 Annual Report, included elsewhere in this prospectus, for additional information. AEPTCo does not expect Tax Reform to have a material impact on future net income, but does anticipate Tax Reform to have an unfavorable impact on future cash flows.

CYBER SECURITY

Cyber security presents a growing risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to the AEP System are potentially disruptive to people, property and commerce and create risk for business, investors and customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support their functions in cyber security as well as redefines how the government interfaces with critical infrastructure, such as the electric grid. The AEP System already operates under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that was being developed through this executive order was reviewed by FERC and the U.S. Department of Energy (DOE). In 2014, the DOE published an Energy Sector Cyber Security Framework Implementation Guide for utilities to use in adopting and implementing the National Institute of Standards and Technology framework. AEP continues to be actively engaged in the framework process.

The electric utility industry is one of the few critical infrastructure functions with mandatory cyber security requirements under the authority of FERC. The Energy Policy Act of 2005 gave FERC the authority to oversee reliability of the bulk power system, including the authority to implement mandatory cyber security reliability standards. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation's Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP began participating in the NERC grid security and emergency response exercises, GridEx, in 2013 and has continued to participate in the bi-yearly exercises through 2017. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security and authentication. The AEP System is constantly scanned for risks or threats. Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, AEP continually assesses its cyber security tools and processes to determine where to strengthen its defenses. Management continually reviews its business continuity plan to develop an effective recovery effort that decreases response times, limits financial impacts and maintains customer confidence following any business interruption. Management works closely with a broad range of departments, including Legal, Regulatory, Corporate Communications, Audit Services, Information Technology and Security, to ensure the corporate response to consequences of any breach or potential breach is appropriate both for internal and external audiences based on the specific circumstances surrounding the event.

Management continues to take steps to enhance the AEP System's capabilities for identifying risks or threats and has shared that knowledge of threats with utility peers, industry and federal agencies. AEP operates a Cyber Security Intelligence and Response Center responsible for monitoring the AEP System for cyber threats as well as collaborating with internal and external threat sharing partners from both industry and government. AEP is a member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center.

AEP has partnered in the past with a major defense contractor who has significant cyber security experience and technical capabilities developed through their work with the U.S. Department of Defense. AEP works with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other. AEP continues to work with a nonaffiliated entity to conduct several discussions each year about recognizing and investigating cyber vulnerabilities. Through these types of efforts, AEP is working to protect itself while helping its industry advance its cyber security capabilities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about AEPTCo's critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

AEPTCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

AEPTCo recognizes regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the timing of expense and income recognition is matched with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, regulatory assets are recorded on the balance sheet. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, regulatory liabilities are recorded when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. Refer to Note 5 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition

Transmission Revenue Accounting

Pursuant to an order approved by the FERC, the AEP East Transmission Companies and the AEP West Transmission Companies are included in the OATT administered by PJM and SPP, respectively. The FERC order implemented an annual transmission revenue requirement for each of the AEP East Transmission Companies and the AEP West Transmission Companies. Under this requirement, AEPSC, on behalf of the AEP East Transmission Companies and the AEP West Transmission Companies, makes annual filings in order to recover prudently incurred costs and an allowed return on plant in service. An annual formula rate filing is made for each calendar year using estimated costs, which is used to determine the billings to PJM and SPP ratepayers. The annual rate filing is compared to actual costs with any over- or under-recovery being trued-up with interest and recovered in a future year's rates.

In accordance with the accounting guidance for "Regulated Operations - Revenue Recognition", AEPTCo recognizes revenue related to OATT rate true-ups immediately following the annual FERC filings. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, AEPTCo evaluates long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. AEPTCo utilizes a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value

of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, AEPTCo records an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. Any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, AEPTCo estimates fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions on the use of the asset. AEPTCo performs depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of “Property, Plant and Equipment” accounting guidance, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management’s analysis of the benefits of the transaction.

ACCOUNTING PRONOUNCEMENTS

See Note 2 - New Accounting Pronouncements in the 2017 Annual Report, included elsewhere in this prospectus, for information related to accounting pronouncements adopted in 2017 and pronouncements effective in the future.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

On July 26, 2016, the Audit Committee of the Board of Directors (the "Audit Committee") of AEP determined not to renew the engagement of Deloitte & Touche LLP, the independent registered public accounting firm or independent auditor ("Deloitte"), as applicable, for the audits of the consolidated financial statements as of and for the fiscal year ending December 31, 2017 of AEP and certain of its subsidiaries, including AEP Transmission Company, LLC and subsidiaries (the "Company" or "AEPTCo"). On July 26, 2016, the Audit Committee appointed PricewaterhouseCoopers LLP as the independent registered public accounting firm or independent auditor, as applicable ("PwC"), to audit the financial statements of AEP and such subsidiaries for the fiscal year ending December 31, 2017. The Audit Committee invited several accounting firms to participate in a competitive bidding process, including Deloitte. The decision to retain PwC was made by the Audit Committee. This action effectively dismissed Deloitte as the independent registered public accounting firm or independent auditor, as applicable, of AEP and such subsidiaries effective upon Deloitte's completion of its procedures on the financial statements of AEP and such subsidiaries as of and for the year ended December 31, 2016.

The audit reports of Deloitte on the consolidated financial statements of AEP and its subsidiaries as of and for the fiscal years ended December 31, 2014 and 2015 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principles. During AEP's fiscal years ended December 31, 2014 and 2015, and the subsequent interim period through July 26, 2016, the date of PwC's appointment, there were no disagreements between AEP or its subsidiary registrants and Deloitte on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure (within the meaning of Item 304(a)(1)(iv) of Regulation S-K) and there were no reportable events (as defined by Item 304(a)(1)(v) of Regulation S-K).

We have provided a copy of the above disclosures to Deloitte and requested Deloitte to provide us with a letter addressed to the SEC stating whether or not Deloitte agrees with those disclosures related to Deloitte. A copy of Deloitte's letter, dated March 22, 2018, is attached as Exhibit 16(a) to the registration statement of which this prospectus forms a part.

During AEP's fiscal years ended December 31, 2014 and 2015, and the subsequent interim period through July 26, 2016, the date of the appointment of PWC, neither AEP nor anyone on its behalf consulted with PWC regarding (i) either the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the consolidated financial statements of AEP or any of its subsidiary registrants, and no written report or oral advice was provided by PWC to AEP and its subsidiary registrants that PWC concluded was an important factor considered by AEP and its subsidiary registrants in reaching a decision as to the accounting, auditing, or financial reporting issue; or (ii) any matter that was the subject of either a disagreement as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions or a reportable event as described in Item 304(a)(1)(v) of Regulation S-K.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

Fixed Rate Debt

Based on the borrowing rates currently available for bank loans with similar terms and average maturities, the fair value of AEPTCo's long-term debt, excluding revolving credit agreements and commercial paper, was $2.8 billion as of December 31, 2017. The book value of AEPTCo's long-term debt, net of discounts and deferred financing fees and excluding revolving credit agreements and commercial paper, was $2.6 billion as of December 31, 2017. Management performed an analysis calculating the impact of changes in interest rates on the fair value of long-term debt, excluding revolving credit agreements and commercial paper, as of December 31, 2017. An increase of 10% in interest rates used to calculate fair value (from 5.0% to 5.5%, for example) as of December 31, 2017 would decrease the fair value of debt by $87 million and a decrease in interest rates of 10% as of December 31, 2017 would increase the fair value of debt by $92 million at that date.

Corporate Borrowing Program

As of December 31, 2017, AEPTCo had $16 million of utility money pool borrowings outstanding under the AEP Corporate Borrowing Program, which is funded by commercial paper. Due to the short-term nature of these financial instruments, the carrying value of any outstanding short term debt would approximate fair value. Using a hypothetical continuous level of $100 million in utility money pool borrowings outstanding, the impact of a hypothetical 10% increase or decrease in interest rates for commercial paper would increase or decrease AEPTCo's annual interest expense by less than $1 million.

Credit Risk

The State Transcos are regulated for rate-making purposes exclusively by FERC and employ a formula rate tariff design that incorporates forward looking -plant in service. As electric transmission utilities with rates regulated by FERC, the State Transcos earn revenues through tariff rates charged for the use of their electric transmission systems. The State Transcos establish transmission rates each year through formula rate filings with FERC. The rate filings calculate the revenue requirement needed to cover the costs of operation and debt service and to earn an allowed return on equity. These rates are then included in the OATT for SPP and PJM. SPP and PJM collect the revenue requirement from transmission customers under their respective OATTs. The transmission customers under the OATTs include the AEP Operating Companies, other investor-owned utilities, electric cooperatives, municipal entities and power marketers.

AEPTCo's primary credit risk is with the AEP Operating Companies. For the years ended December 31, 2017, 2016 and 2015, the AEP Operating Companies were responsible for approximately 80%, 77% and 73%, respectively, of AEPTCo's consolidated transmission revenues. Any financial difficulties experienced by the AEP Operating Companies could negatively impact AEPTCo's business. However, PJM and SPP, as the billing agents of the State Transcos, have strict credit policies for its members' customers, which include customers using our transmission systems. Specifically, PJM and SPP require a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit scoring model and other factors, from any customer using a member's transmission system.

BUSINESS

Overview

AEPTCo, a Delaware limited liability company organized in 2006, is the holding company of seven regulated transmission-only electric utilities. AEPTCo is an indirect wholly-owned subsidiary of AEP. AEPTCo's business consists of developing and building new transmission facilities at the request of the regional transmission organizations in which we operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers.

AEPTCo's seven wholly-owned public utility companies are:

- AEP Appalachian Transmission Company, Inc. ("APTCo"),
- AEP Indiana Michigan Transmission Company, Inc. ("IMTCo"),
- AEP Kentucky Transmission Company, Inc. ("KTCo"),
- AEP Ohio Transmission Company, Inc. ("OHTCo"),
- AEP West Virginia Transmission Company, Inc. ("WVTCo"),
- AEP Oklahoma Transmission Company, Inc. ("OKTCo") and
- AEP Southwestern Transmission Company, Inc. ("SWTCo").

The State Transcos are independent of but overlay AEP's existing electric utility operating companies: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and Wheeling Power Company (collectively, the "AEP Operating Companies"). The State Transcos develop, own, operate, and maintain their respective transmission assets. Assets of the State Transcos interconnect to transmission facilities owned by the AEP Operating Companies and unaffiliated transmission owners within the footprints of PJM and SPP. PJM and SPP are regional transmission organizations ("RTOs") mandated by the Federal Energy Regulatory Commission ("FERC") to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. PJM is a regional transmission organization serving approximately 65 million people throughout 13 states and the District of Columbia. APTCo, IMTCo, KTCo, OHTCo and WVTCo are located within PJM. SPP is a regional transmission organization serving over 18 million people in fourteen states. OKTCo and SWTCo are located within SPP.

The State Transcos are regulated for rate-making purposes exclusively by FERC and employ a formula rate tariff design that incorporates forward looking plant in service. Activity between the State Transcos and the AEP Operating Companies is governed by service agreements. Individual State Transcos (a) have obtained the approvals necessary to operate in Indiana, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, (b) are authorized to submit projects for commission approval in Virginia and (c) have been granted consent to enter into a joint license agreement that will support investment in Tennessee. The application for regulatory approval to operate in Louisiana is under consideration, while the application for regulatory approval to operate in Arkansas was denied.

As electric transmission utilities with rates regulated by FERC, the State Transcos earn revenues through tariff rates charged for the use of their electric transmission systems. The State Transcos establish transmission rates each year through formula rate filings with FERC. The rate filings calculate the revenue requirement needed to cover the costs of operation and debt service and to earn an allowed return on equity. These rates are then included in the OATT for SPP and PJM. SPP and PJM collect the revenue requirement from transmission customers under their respective OATTs. The transmission customers under the OATTs include the AEP Operating Companies, other investor-owned utilities, electric cooperatives, municipal entities and power marketers.

Development of Business

Each State Transco is geographically aligned with an existing AEP Operating Company. Each State Transco develops and owns new transmission assets that are physically connected to the electric system owned and operated by the AEP Operating Companies (the "AEP System"). Our business strategy is to own, operate, maintain and invest in transmission infrastructure in order to maintain and enhance system integrity and grid reliability, grid security, safety, reduce transmission constraints and facilitate interconnections of new generating resources and new wholesale customers, as well as enhance competitive wholesale electricity markets.

Development of transmission projects through the State Transcos is primarily driven by:

1. Projects assigned to the AEP System as a result of the regional planning initiatives conducted by the RTOs. The RTOs identify the need for transmission in support of regional reliability, transmission service, congestion mitigation, public policy, to support the integration of new generation resources and to support the retirement of generation resources. These projects are referred to as "Regional Projects."

2. Improvements to local area reliability by upgrading, rebuilding or replacing existing, aging infrastructure at the AEP Operating Companies. Together with New Interconnections described below, these projects are referred to as "Local Projects."

3. Construction of new facilities to support customer points of delivery ("New Interconnections").

Transmission investment across AEP is primarily driven by the need to revitalize aging infrastructure, our desire to enhance reliability at a local level to improve the customer experience, compliance with regulatory, industry, and governmental standards, requirements to improve telecommunication capability to keep up with changing technologies, and the obligation to address grid limitations identified by the RTOs. The State Transcos are not limited to investing in projects addressing particular transmission drivers. AEP has developed project selection guidelines that help determine which transmission assets can be built, owned and operated by the State Transcos. In essence, the need on the transmission grid determines the transmission project and the project selection guidelines help determine which components of the transmission project will be placed in the State Transcos.

Generally, greenfield transmission, partial or complete refurbishment of extra high voltage transmission, and complete refurbishment of lower voltage transmission assets qualify for transmission investment in the State Transcos. In the foreseeable future, AEPTCo expects the majority of its transmission investment to go towards improving aging infrastructure, local reliability and upgrades to telecommunication and operational stacks.

Each State Transco is responsible for developing, constructing, owning, operating, and maintaining its respective transmission facilities.

Development of Regional Projects

Both PJM and SPP have sophisticated, long-term transmission planning processes to identify needed system upgrades. In their respective planning processes, each RTO identifies needed upgrades and then publishes those results in an annual plan. The following is an overview of the PJM and SPP regional transmission expansion plans.

The PJM Regional Transmission Expansion Plan (“RTEP”) identifies transmission system enhancements to meet the reliability requirements and ensure an efficient real-time operations of PJM electric transmission grid. PJM’s RTEP process encompasses a comprehensive assessment of system performance, adherence to PJM reliability criteria and compliance with the NERC Standards. The RTEP process also examines market efficiency to identify transmission enhancements that lower costs to consumers by relieving congested lines. Transmission enhancements are examined for their feasibility, impact and costs. This process culminates in a recommended RTEP for the entire PJM footprint that is submitted to PJM’s independent Board of Managers for consideration and approval each year. Under the PJM governing documents, transmission owning utilities in PJM are required to construct Board-approved RTEP projects.

The SPP Transmission Expansion Plan (“STEP”) identifies distinct areas of transmission planning for the future development of the SPP transmission grid. SPP’s engineering staff works closely with members, regulators, and systems interconnecting with SPP to plan future transmission system expansion needs and provide transmission and generation interconnection service necessary to facilitate reliable and efficient delivery of generation resources to end-use customers. The SPP Board of Directors reviews the STEP annually for approval and endorsement of proposed projects. Under the SPP governing documents, transmission owning utilities in SPP are required to construct projects approved by the SPP Board of Directors.

Development of Local Projects

The State Transcos develop additional transmission projects to meet their fundamental obligation to serve customers and to ensure operability of the grid as designed. Local Projects include replacement of aging or obsolete infrastructure and enhancements to improve local reliability needs and support customer connections. These projects focus on upgrading, rebuilding or replacing specific assets that have surpassed their useful life expectancy and whose performance and condition significantly increase their risk of failure. AEP evaluates several criteria to determine the need for Local Projects. These criteria include age, recorded performance issues, condition assessment, anticipated maintenance requirements and criticality to the grid. Projects are assigned to the State Transcos based upon a defined set of criteria that are outlined in AEP’s Project Selection Guidelines. The need on the transmission grid determines the transmission project and project selection guidelines help determine which components of the transmission project will be placed in the State Transcos.

Project Approval

Regional Projects are subject to approval by the respective RTO Board. This is preceded by an open stakeholder review and comment period as part of the RTO planning process. Once approved, these Regional Projects are mandatory and must be constructed by the designated transmission owner pursuant to FERC rules that govern the RTOs.

In PJM, Local Projects do not require PJM Board approval; however, the State Transcos review Local Projects with relevant stakeholders, including PJM. This public vetting provides the stakeholders whose constituents will pay for these projects the opportunity to review and, if desired, to question and comment on those Local Project plans. Discussions for a corresponding process in SPP are ongoing.

State Siting Approval

No prior regulatory approval is typically required to replace existing assets with new equipment of the same electrical rating. Approval is generally required for the replacement of lower voltage facilities with higher voltage lines. These requirements vary by state.

Competition

Local Projects and new interconnections are not subject to competition from other non-affiliated providers, owners or developers of transmission assets or services.

In PJM, Regional Projects situated within a single transmission zone, such as the zone in which the AEP System operates in PJM (the “AEP Transmission Zone”), are not subject to competition. These include: (i) Regional Projects that are fully cost allocated to the AEP Transmission Zone, (ii) time-sensitive Regional Projects that address planning criteria violations that occur within three years, and (iii) Regional Projects that are upgrades to existing transmission facilities. Regional Projects not meeting these criteria must be awarded by PJM or SPP in a process approved by FERC under Order 1000, and generally contemplates more than one bidder for any particular Regional Project.

In PJM, projects with cost allocation in more than one zone are subject to competition. In the last few years an average of one project per year met this criterion. Projects with cost allocation to a single zone are not subject to competition.

In most instances within SPP, greenfield transmission at or above 100 kilovolts (“kV”) is competitive. Most of the transmission solutions in SPP are comprised of upgrades to existing facilities and therefore are not subject to competition. Upkeep of existing assets is a fundamental obligation of a transmission owner and revitalization of existing assets is not open to competition in PJM and SPP.

Existing and Forecasted Projects

The State Transcos are geographically diverse and have assets in service or under construction across two RTOs and in seven states, with additional states pending approval. We anticipate the need for extensive additional investment in transmission infrastructure within PJM and SPP to maintain the required level of grid reliability, resiliency, security and efficiency and to address an aging infrastructure. We also foresee the need to construct additional transmission facilities based on changes in generating resources such as wind or solar projects, generation additions or retirements, and additional new customer interconnections. We will continue our investment to enhance physical and cyber security of our assets, and are also investing in improving the telecommunication network that supports the operation and control of the grid. Finally, our fundamental obligation to meet state, federal, regulatory and industry standards will continue to drive investment in this category of projects.

A key part of our business is replacing and upgrading transmission facilities, assets and components of the existing AEP System as needed to maintain reliability. Over 5,800 circuit miles of AEP's transmission lines were built more than seventy years ago. Significant quantities of major transmission equipment, such as transformers and circuit breakers, on AEP’s grid are also at or near the end of their useful life. The State Transcos provide the capability to upgrade existing facilities due to their condition as a result of their age.

Operations

As transmission-only companies, our State Transcos function as conduits, allowing for power from generators to be transmitted to local distribution systems. The transmission of electricity by our State Transcos is a central function to the provision of electricity to residential, commercial and industrial end-use consumers. The operations performed fall into the following categories:

- planning;
- engineering, procurement and project services;
- maintenance; and
- real time operations.

Planning

AEPSC transmission employees ("AEP Transmission") use detailed system models and load forecasts to develop our system capital plans. Expansion capital plans are used to identify projects that would address potential future reliability issues and service to new customers, connect new generation resources and/or produce economic savings for customers by eliminating constraints.

AEP Transmission works closely with PJM and SPP in the development of our system capital plans by performing technical evaluations and detailed studies. As the regional planning authorities, PJM and SPP approve regional system improvement plans which include projects to be constructed by their members, including our State Transcos.

Engineering , Procurement and Project Services

AEP Transmission maintains in-house engineering expertise in all facets of the transmission AEP system. AEP Transmission also performs services for the estimating, project management and construction management services for the capital work plan. AEP Transmission performs much of this work and utilizes outside services as needed to supplement capacity to match the work load. AEP Transmission directly procures the majority of equipment used in the construction of its transmission projects. The majority of the construction work is performed by outside contractors.

Maintenance

AEP Transmission performs maintenance, field operations and emergency restoration of our State Transco transmission line and station facilities. AEP Transmission develops and tracks preventive maintenance plans to promote safe and reliable operation of our systems. By performing preventive maintenance on our assets, AEP Transmission minimizes the need for reactive maintenance, resulting in improved reliability and compliance with all applicable NERC and RTO requirements.

Real Time Operations

From our System Control Center located in New Albany, Ohio, transmission system operators continuously monitor the performance of the transmission system of the AEP System. AEP Transmission uses software and communication systems to perform analysis to maintain security and reliability and for contingency planning triggered by any unplanned events. From our geographically dispersed Transmission Dispatch Centers (situated in Roanoke, Virginia; New Albany, Ohio; Tulsa, Oklahoma; and Shreveport, Louisiana) our transmission dispatchers are responsible for the activities related to taking equipment in and out of service to ensure capital construction projects and maintenance programs are completed safely and reliably.

Operating Contracts

AEPSC has executed a services agreement pursuant to which AEPSC has agreed to provide services to each of the State Transcos. AEPSC is an AEP service subsidiary that provides management and professional services to AEP and its subsidiaries. AEPSC provides four categories of service to the State Transcos: project evaluation and permitting services, project development services, operation and management services and business services, including billing, insurance, human resources and IT services. All of these services are provided at cost. Additionally, each State Transco has executed a services agreement with the respective incumbent AEP Operating Company in its state or footprint.

Regulatory Environment

Federal regulators and public policy currently support further investment in transmission. The growth and changing mix of electricity generation and wholesale power sales, combined with historically inadequate transmission investment have resulted in significant transmission constraints across the United States and increased stress on aging transmission equipment. Transmission system investments increase system reliability and reduce the frequency of power outages. Such investments can also reduce transmission constraints and improve access to lower cost generation resources, resulting in a lower overall cost of delivered electricity for end-use consumers. FERC has encouraged new investment in the transmission sector by implementing various financial and other incentives.

FERC has issued orders to promote non-discriminatory transmission access for all transmission customers and has mandated that all transmission systems over which it has jurisdiction must be operated in a comparable, non-discriminatory manner such that any seller of electricity affiliated with a transmission owner or operator is not provided with preferential treatment. FERC requires compliance with certain reliability standards by transmission owners and may take enforcement actions for violations, including the imposition of substantial fines. NERC is responsible for developing and enforcing these mandatory reliability standards. We continually assess our transmission systems against standards established by NERC, as well as the standards of applicable regional entities under NERC that have been delegated certain authority for the purpose of proposing and enforcing reliability standards.

Federal Regulation and Formula Rate Setting at FERC

The State Transcos are regulated by FERC as electric transmission companies. FERC is an independent regulatory commission that regulates the transmission and wholesale sales of electricity in interstate commerce. FERC also administers accounting and financial reporting regulations and standards of conduct for the companies it regulates.

Generally speaking, FERC has approved a formula rate mechanism to recover the State Transcos' costs of investments in transmission facilities. The approved formula rate mechanism established a revenue requirement for transmission services over the facilities of the State Transcos under the respective PJM and SPP OATTs, as applicable, and implemented a transmission cost of service formula rate. The PJM and SPP OATTs provide standard terms and conditions to ensure consistent service availability and treatment of all transmission customers.

An OATT is the FERC rate schedule that provides the terms and conditions for transmission and related services on a transmission provider's transmission system. FERC requires transmission providers to offer transmission service to all eligible customers (load-serving entities, generators, and customers in states with supplier choice) on a non- discriminatory basis. Through an OATT, FERC establishes transmission service rates for transmission owners, as derived from their annual transmission revenue requirement ("ATRR"). The ATRR consists of the cost of capital (debt and equity costs), plus income statement items such as O&M costs, depreciation, interest and taxes. The applicable RTO collects the transmission owner's ATRR requirements from the transmission customers and provides payment to the transmission owner.

In November 2016, certain AEP affiliates, including the eastern State Transcos, filed an application with the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to estimated expenses. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. Effective January 1, 2017, the modified PJM OATT formula rates were implemented, subject to refund, based on projected 2017 calendar year financial activity and projected plant balances. In October 2017, AEP's western transmission subsidiaries filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected 2018 calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures.

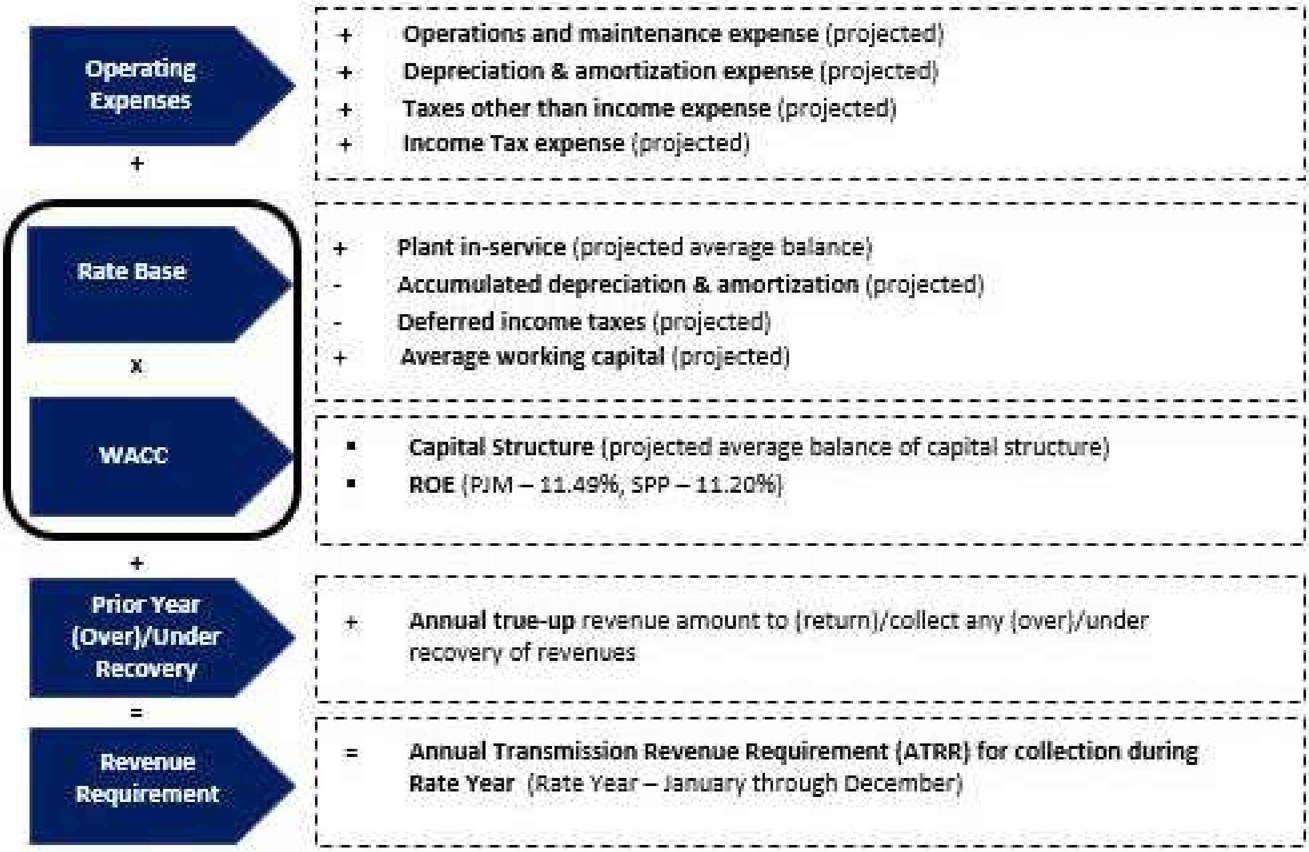
Under the terms and conditions provided in the modified PJM and SPP OATTs, each State Transco will file its ATRR annually in October, establishing rates for the one-year forward period of January through December of the following year ("Rate Year"). Concurrently, the ATRR includes a true-up calculation for the previous Rate Year's billings, eliminating any potential for over- or under-recovery of expenses or the allowed return on and of the plant in-service.

PJM collects the eastern State Transcos' ATRR requirements from the PJM transmission customers and provides payment to the eastern State Transcos. SPP collects the western State Transcos' ATRR requirements from the SPP transmission customers and provides payment to the western State Transcos.The ATRR calculation allows the State Transcos to collect revenues during the Rate Year for the current year's estimated financial activity plus the average projected net plant in-service through the end of the filing year. This provides the State Transcos with a mechanism for revenue recovery of and on actual and projected capital investments.

The most recent ATRR information for the eastern State Transcos was filed in October 2017. The annual true-up calculation provides for the recovery of changes in the cost of capital. Any over or under- recovery of revenue is calculated with interest.

The most recent ATRR information for the western State Transcos was filed in October 2017. The annual true-up calculation provides for the recovery of changes in the cost of capital.

The table below illustrates the formula rate calculation for the State Transcos:



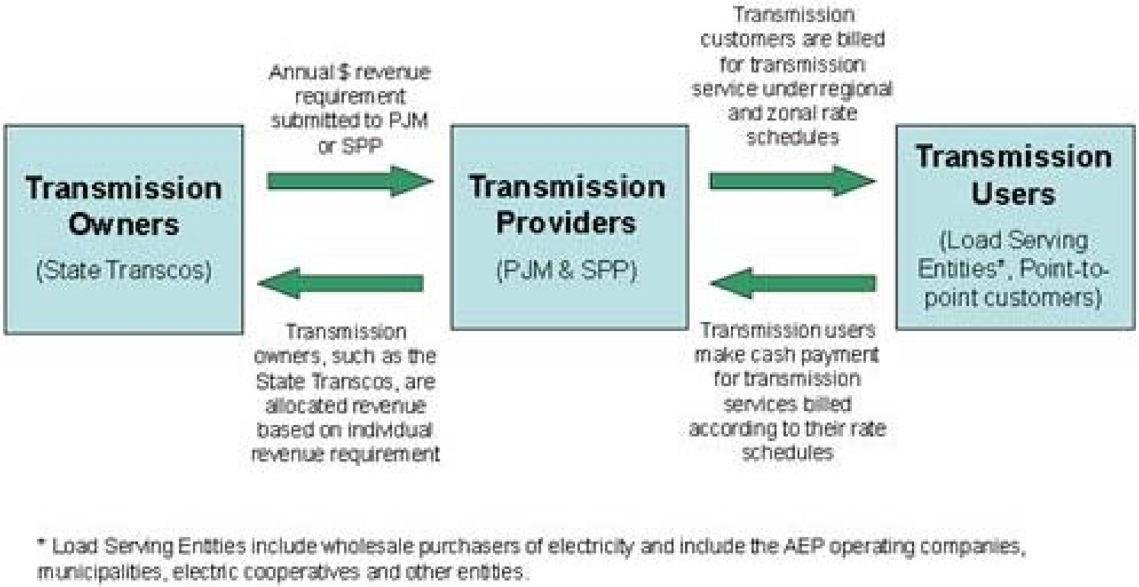
State Regulation

The public service commissions in the states where our State Transcos' assets are located do not have jurisdiction over the State Transco's rates or terms and conditions of service. However, certain transmission facilities are subject to certification and/or siting and financing requirements specific to each state. While these proceedings require a statement and justification of need, they also determine line routes and substation locations with the least impact to the environment and general public. The state public service commission or a designated entity will review the State Transco's application to certify the project.

For a further discussion of rate and regulatory proceedings at FERC and state public service commissions, see Note 3 to our audited financial statements and related notes included elsewhere in this prospectus.

Sources of Revenue

The State Transcos submit their annual revenue requirement to their respective RTO (PJM or SPP). PJM and SPP then charge their respective transmission customers under their respective OATT to collect the revenue requirement of all transmission owners under their respective OATT. The revenues collected from transmission customers are distributed by PJM and SPP to the applicable State Transcos, as transmission owners, based on their individual OATT revenue requirement. The illustration below depicts the revenue collection process.



Principal Customers

For the year ended December 31, 2017, AEP Operating Companies were responsible for approximately 80% of the consolidated transmission revenues of AEPTCo. Load serving entities are responsible for their portion of our PJM and SPP formula rate revenue requirement. Our remaining revenues are primarily generated from providing service to other entities such as alternative electricity suppliers and wholesale customers that provide electricity to end-use consumers.

Billing

PJM and SPP are responsible for billing and collecting our transmission service revenues as well as independently administering the transmission tariff in their respective service territory. As the billing agents for our State Transcos, PJM and SPP independently bill our customers on a monthly basis and collect fees for the use of our transmission systems. Should one of these entities default on its payment to the SPP or PJM, that portion of the revenue requirement is shared among the other transmission service customers in the RTO.

Employees

As of December 31, 2017, AEPTCo had no employees. Each State Transco and AEPSC has executed a services agreement pursuant to which AEPSC has agreed to provide services to each of the State Transcos. All such services are provided at cost. Additionally, each State Transco has executed a services agreement with the respective incumbent AEP Operating Company in its state. These form the core operative agreements by which each State Transco obtains services.

Seasonality

The State Transcos' cost-based formula rates with a true-up mechanism mitigate the seasonality of cash flows as amounts are collected evenly throughout the year. Our State Transcos accrue or defer revenues annually in June of each year to the extent that the actual revenue requirement for the prior PJM and SPP planning year was higher or lower, respectively, than the amounts billed. To the extent that a State Transco's amounts billed are less than its revenue requirement for the annual period, a revenue accrual is recorded in June for this annual difference.

Environmental Matters

The State Transcos are subject to federal, state and local environmental laws and regulations, which impose requirements on wastewater discharges, regulate the issuance of permits for our construction activities, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances.

The State Transcos currently incur costs to meet the requirements in our permits and satisfy obligations imposed as part of the authorization for the construction of new or expanded facilities. Typically these costs are incorporated into cost of service rates.

Superfund addresses liabilities for costs to clean up contaminated sites due to disposal of hazardous substances. Liabilities relating to investigation and remediation of contamination, as well as other liabilities concerning hazardous materials or contamination, such as claims for personal injury or property damage, can arise at third party sites where such wastes have been treated or disposed of, as well as properties currently owned or operated by us. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified Superfund sites.

Our assets and operations also involve the use of materials classified as hazardous, toxic or otherwise dangerous. Some of these properties include aboveground or underground storage tanks and associated piping. Our facilities and equipment are often situated on or near property owned by others so that, if they are the source of contamination, others' property may be affected. We are not aware of any pending or threatened claims against us with respect to environmental contamination relating to our properties, or of any investigation or remediation of contamination at our properties that entail costs likely to materially affect us.

Claims have been made or threatened against electric utilities for bodily injury, disease or other damages allegedly related to exposure to electromagnetic fields associated with electric transmission and distribution lines. While we do not believe that a causal link between electromagnetic field exposure and injury has been generally established and accepted in the scientific community, the liabilities and costs imposed on our business could be significant if such a relationship is established or accepted. We are not aware of any pending or threatened claims against us for bodily injury, disease or other damages allegedly related to exposure to electromagnetic fields and electric transmission and distribution lines that entail costs likely to have a material adverse effect on our results of operations, financial position or liquidity.

Related Party Transactions

AEPTCo, the State Transcos, AEP and their affiliates engage in related party transactions. See Note 16 to our audited financial statements included elsewhere in this prospectus.

Properties

Our transmission facilities are located in Indiana, Kentucky, Michigan, Ohio, Oklahoma, and West Virginia and include the following assets:

- 1,438 circuit miles of overhead transmission lines rated at voltages of 34.5 kV to 765 kV;
- other transmission equipment necessary to safely operate the system (e.g., monitoring and metering equipment);
- associated real property held in fee, by lease, or by easement grant; and
- an approximately 190,000 square-foot AEP Transmission headquarters facility in New Albany, Ohio, including furniture, fixtures and office equipment.

Our State Transcos do not hold title to the majority of real property on which their electric transmission assets are located. Instead, under the provisions of certain affiliate contracts, each of our State Transcos are permitted to occupy and maintain their facilities upon real property held by the respective AEP Operating Company that overlays its operations. The ability of the State Transcos to continue to occupy such real property is dependent upon the terms of such affiliate contracts and upon the underlying real property rights of the AEP Operating Company, which may be encumbered by easements, mineral rights and other similar encumbrances that may affect the use of such real property.

Legal Proceedings

For a discussion of the significant legal proceedings, including, but not limited to, litigation and other matters involving the Company, reference is made to the information in Note 4 and Note 6 to our audited consolidated financial statements, included elsewhere in this prospectus.

In the normal course of business from time to time, other lawsuits, claims, environmental actions and other governmental proceedings can arise against the Company. To the extent that damages are assessed in any of these actions or proceedings, the Company believes that its insurance coverage is adequate. Although we cannot accurately predict the amount of any liability that may ultimately arise with respect to such matters, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on our financial condition or results of operations.

MANAGEMENT

Set forth below is information regarding AEPTCo's executive officers and members of our board of managers. There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer or managers during the past ten years. Some officers serve in the same capacities at AEP and the Company. All of the managers of the Company are employees of AEPSC.

Listed below are the executive officers and managers at February 21, 2018.

Nicholas K. Akins
Chairman of the Board, Chief Executive Officer and Manager of the Company
Chairman of the Board, President and Chief Executive Officer of AEP
Age 57
Chairman of the Board of AEP since January 2014, President of AEP since January 2011 and Chief Executive Officer of AEP since November 2011.
Mr. Akins is a board member of Fifth Third Bancorp.

Lisa M. Barton
President, Chief Operating Officer and Manager of the Company
Executive Vice President - Transmission of AEP
Age 52
Executive Vice President - Transmission of AEPSC since August 2011. Ms. Barton is a board member of Transource Energy, a joint venture with Great Plains Energy. She also serves on the board of directors of Electric Transmission Texas (ETT), a joint venture with Berkshire Hathaway Energy Company.

David M. Feinberg
Vice President, Secretary and Manager of the Company
Executive Vice President, General Counsel and Secretary of AEP
Age 48
Executive Vice President of AEP since January 2013.

Lana L. Hillebrand
Executive Vice President and Chief Administrative Officer of AEP

Age 57
Executive Vice President since January 2017. She was Senior Vice President from December 2012 to December 2016 and Chief Administrative Officer since December 2012.

Charles Patton
Executive Vice President-External Affairs of AEP
Age 58
Executive Vice President-External Affairs of AEP since January 2017. He was President and Chief Operating Officer of Appalachian Power Company from June 2010 to December 2016.

A. Wade Smith
Manager of the Company
Age 53
Mr. Smith is Senior Vice President-Grid Development for AEPSC since August 2015. He was President and Chief Operating Officer of AEP Texas Central Company and AEP Texas North Company from 2010 to August 2015.

Brian X. Tierney
Vice President, Chief Financial Officer and Manager of the Company
Executive Vice President and Chief Financial Officer of AEP since October 2009.
Age 50

COMPENSATION DISCUSSION AND ANALYSIS

The following information relates to AEP. AEP Transmission Company, LLC does not establish its own executive compensation policy and procedures and there is no separate Compensation Committee of its Board of Managers. In this Compensation Discussion and Analysis and the executive compensation tables and narratives that follow, we discuss 2017 compensation paid to our named executive officers for services provided to AEP and to AEP Transmission Company, LLC, any references to “us” or “we” refers to AEP..

This section explains AEP’s compensation philosophy, summarizes its compensation programs and reviews compensation decisions for the following named executive officers:

Name	Title
Mr. Akins	Chairman, Chief Executive Officer and President
Mr. Tierney	Executive Vice President and Chief Financial Officer
Mr. Feinberg	Executive Vice President and General Counsel
Ms. Barton	Executive Vice President Transmission
Ms. Hillebrand	Executive Vice President and Chief Administrative Officer

Executive Summary

2017 Business Performance Highlights.

During 2017, AEP continued on its path to reposition the Company as the next premier regulated energy company. In January 2017, AEP completed the sale of its unregulated Lawrenceburg, Waterford, Darby and Gavin generation plants. We believe that this will allow us to produce more consistent earnings by removing the volatility associated with those competitive generation plants and their exposure to the capacity and energy markets. We have successfully refocused our business, with most of our forecasted earnings coming from our regulated operations and contracted renewables business. We anticipated lower operating earnings this year, compared with last year, due to the sale of these competitive generation assets. We used the cash proceeds from the sale to further invest in our transmission business and renewable projects. Although operating earnings were lower in 2017 compared to 2016, we believe that we made the appropriate strategic decision.

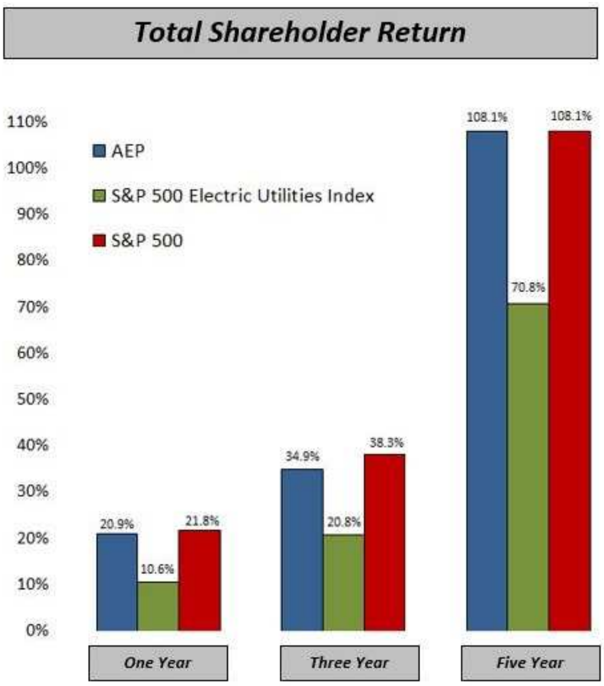
Our service area experienced very mild weather in 2017 which negatively impacted earnings by 13 cents per share compared to a normal weather year and 19 cents compared to 2016 results, but we took proactive steps to reduce expenses to offset the impact of the mild weather. Our 2017 non-GAAP operating earnings were $3.68 per share, which was at the high end of our revised operating earnings guidance. Throughout this CD&A, we refer to operating earnings, which is a non-GAAP financial measure. For 2017, GAAP earnings per share were $3.89, which is $0.21 per share higher than operating earnings. The difference between 2017 GAAP earnings and operating earnings was largely due to a gain on the sale of competitive generation assets.

We continue to increase the capital investment in core utility operations to support operating earnings growth of 5 to 7 percent. Those investments will provide enhanced reliability for our customers along with stable, positive returns for our shareholders. AEP plans to invest approximately $8.3 billion in its transmission businesses during 2018-2020, nearly half of the Company's total capital investment forecast.

In 2017, our Transmission Holding Company business grew and contributed 72 cents per share to operating earnings, an increase of 33 percent over 2016. AEP Transmission Holding Company has grown to become one of AEP's largest subsidiary companies.

We also continued to place a heavy focus on our safety performance. In 2017, the Company did not experience a fatal employee accident, but did sustain two contractor fatalities.

In October 2017 the Company increased its quarterly dividend by 5.1 percent, the eighth consecutive yearly increase. As shown in the chart below, AEP’s shareholders received a 20.9 percent total shareholder return in 2017, which was well above the total shareholder return for the S&P 500 Electric Utilities Index of 10.6 percent, with correspondingly similar superior results over the last 3- and 5-years as well.



2017 Goals for Incentive Compensation Plans

With respect to our 2017 annual incentive compensation, the HR Committee:

- Set the operating earnings per share target goal at $3.70, with no payout under the annual incentive plan if operating earnings were below $3.55 per share. The Company's annual operating earnings guidance at the time the HR Committee set the goal was $3.55 - $3.75 per share.

- Set the operating earnings per share needed for a maximum payout at $4.00 per share.

With respect to the 2017 long-term incentive performance unit awards, the HR Committee:

- Set the target for the three year cumulative operating earnings per share based on the same $3.70 target used for the annual incentive plan for 2017, with a six percent growth rate in operating earnings for 2018 and 2019.

2017 Executive Compensation Earned Awards under Annual Incentive Plan

With respect to earned awards under the annual incentive plan, the HR Committee certified the following results and pay outcomes:

- 2017 operating earnings per share of $3.68, which was above the midpoint of the Company's original earnings guidance, produced a score of 83.9 percent.

- The Company performed above target on most of its strategic measures.

- These results produced an overall score of 92 percent of target under the annual incentive plan.

2015-2017 Earned Long-Term Performance Awards

With respect to the long-term incentive performance unit award, the HR Committee certified the following results and pay outcomes:

- Cumulative total shareholder return (TSR) of 38% placed the Company at the 75th percentile relative to the S&P 500 Electric Utilities Industry Index, which resulted in 183.3 percent of the target score.

- Cumulative operating earnings per share was above the target set for this performance period and produced a score of 146.2 percent of target.

- These combined equally weighted scores resulted in a payout of 164.8 percent of target for this performance period.

Compensation Governance Best Practices

Underlying our executive compensation program is an emphasis on good corporate governance practices:

What We Have	What We Don't Have
Significant stock ownership requirements for executive officers, including a stock ownership requirement for the CEO of six times base salary	*No reimbursement or tax gross-up for excise taxes triggered under change in control agreements*
A substantial portion of the compensation for executive officers is tied to	

annual and long-term performance	*No company paid country club memberships for executive officers*
A recoupment policy that allows the Company to claw back incentive compensation	*Generally prohibit personal use of Company provided aircraft, to the extent that such use has an incremental cost to the Company*
An insider trading policy that prohibits our executives and directors from hedging their AEP stock holdings and from pledging Company stock	*No tax gross-ups, other than for relocations*
If there is a change in control, long-term incentive awards have double trigger vesting that results in accelerated vesting of these awards only if the change in control is followed by an involuntary or constructive separation from service	

Results of 2017 Advisory Vote to Approve Executive Compensation

At the Company's annual meeting of shareholders held in April 2017, approximately 85 percent of the votes cast on the Company's say-on-pay proposal voted in favor of the proposal. After consideration of this vote, the HR Committee continued to apply the same principles and philosophy it has used in previous years in determining executive compensation. The HR Committee will continue to consider the outcome of the Company's say-on-pay vote and other sources of stakeholder feedback when establishing compensation programs and making compensation decisions for the named executive officers.

Overview

Principles

The HR Committee oversees and determines AEP's executive compensation (other than that of the CEO). In the case of the CEO, the HR Committee makes recommendations to the independent members of the board of directors about the compensation of the CEO, and the independent board members approve the CEO's compensation.

AEP's executive compensation program is designed to:

- Attract, retain, motivate and reward an outstanding leadership team with market competitive compensation and benefits to achieve both excellent team and individual performance;
- Reflect AEP's financial and operational size and the complexity of its multi-state operations;
- Provide a substantial portion of executive officers' total compensation opportunity in the form of short-term and long-term performance based incentive compensation;
- Align the interests of the Company's named executive officers with those of AEP's shareholders by providing a majority of the compensation opportunity for executive officers in the form of stock-based compensation with a value that is linked to the total return on AEP's common stock and by maintaining significant stock ownership requirements for executives;
- Support the implementation of the Company's business strategy by tying annual incentive awards to operating earnings per share and the achievement of specific strategic and safety objectives; and
- Promote the stability of the management team by creating strong retention incentives with multi-year vesting schedules for long-term incentive compensation.

The HR Committee's independent compensation consultant, Meridian Compensation Partners, LLC (Meridian), participates in HR Committee meetings, assists the HR Committee in developing the compensation program and regularly meets with the HR Committee in executive session without management present.

Opportunity vs. Performance

AEP's executive compensation program generally targets each named executive officer's total direct compensation *opportunity* (base salary, target annual incentive and grant date value of long-term incentive) at the median of AEP's Compensation Peer Group, which consists of 18 companies that operate in our industry. The ultimate value realized from the short- and long-term incentives are based on the Company's short- and long-term performance.

Compensation and Benefits Design

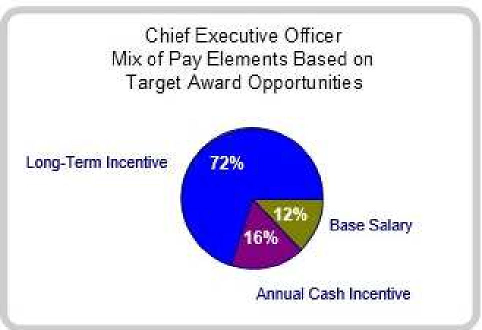
The compensation for our named executive officers includes base salary, annual incentive compensation, long-term incentive compensation and a comprehensive benefits program. The Company aims to provide a balance of annual and long-term incentive compensation that is consistent with the compensation mix provided by AEP's Compensation Peer Group. For annual incentive compensation, the HR Committee balances meeting AEP's operating earnings per share target with strategic and safety objectives. For 2017 annual incentive compensation, operating earnings per share had a 70 percent weight of the overall award opportunity, and the remaining 30 percent weight was tied to strategic and safety goals.

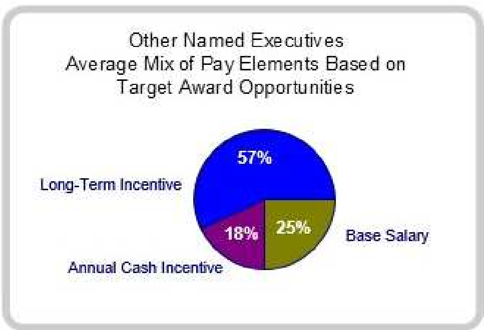
75 percent of our 2017 long-term incentive compensation was awarded in the form of performance units and 25 percent as restricted stock units (RSUs). The performance units are tied to:

(1) AEP's total shareholder return relative to the companies in AEP's Compensation Peer Group; and
(2) AEP's three-year cumulative operating earnings per share relative to a Board-approved target.

The performance units are subject to a three-year vesting period from their January 1, 2017 effective date. The RSUs vest over 40 months from their January 1, 2017 effective date.

As illustrated in the charts below, in 2017, 71 percent of the target total direct compensation for the CEO and 62 percent on average for the other named executive officers was performance-based (target annual incentive compensation and grant date value of performance units). An additional 17 percent of the CEO's target total direct compensation and an additional 13 percent on average for the other named executive officers was provided in the form of time-vesting RSUs (grant date value) which are tied to AEP's stock price.





Compensation Peer Group

The HR Committee, supported by Meridian, annually reviews AEP's executive compensation relative to a peer group of companies that represent the talent markets where we compete to attract and retain executives. The 18 companies included in the Compensation Peer Group were chosen from electric utility companies that were comparable in size in terms of revenues and market capitalization. AEP's Compensation Peer Group for 2017 consisted of the 18 electric utility companies shown below.

AES Corporation	Eversource Energy
Centerpoint Energy, Inc.	FirstEnergy Corp.
Consolidated Edison Inc.	NextEra Energy, Inc.
Dominion Resources, Inc.	PG&E Corporation
DTE Energy Company	PPL Corporation
Duke Energy Corporation	Public Service Enterprise Group Inc.
Edison International	Sempra Energy
Entergy Corporation	Southern Company
Exelon Corporation	Xcel Energy Inc.

The table below shows that, at the time the Compensation Peer Group data was collected, AEP's revenue and market capitalization were above the 50th percentile, and closer to the 75th percentile, of the Compensation Peer Group.

2017 Compensation Peer Group

Compensation Peer Group	Revenue (1)	Market Cap (1)
	($ million)	
25th Percentile	$10,357	$18,089
50th Percentile	$11,604	$24,833
75th Percentile	$16,383	$33,061
AEP	**$15,970**	**$34,436**

(1) The HR Committee selected the 2017 Compensation Peer Group in September 2016 based on each company's fiscal year-end 2015 revenue, and market capitalization as of June 30, 2016.

Annual Market Analysis

Meridian annually provides the HR Committee with an executive compensation study covering each named executive officer position based on survey information derived from the Compensation Peer Group. The Meridian study benchmarked each of our named executive officer's total direct compensation, and each component of compensation, against median target compensation provided by the Compensation Peer Group to officers serving in similar capacities. The market benchmarks were size-adjusted based on AEP's revenue or the business unit revenue under the executive's purview using regression analysis for all positions for which regression analysis was available.

Executive Compensation Program Detail

Summary of Executive Compensation Components. The following table summarizes the major components of the Company's executive compensation program.

Component	Purpose	Key Attributes
Base Salary	• To provide a market-competitive and consistent minimum level of compensation that is paid throughout the year.	• Merit and other salary increases for executives are awarded by the HR Committee based on a variety of factors described below under Base Salary.
Annual Incentive Compensation	• To focus executive officers on achieving annual earnings and other performance objectives that are critical to AEP's success, which for 2017 included: • Operating Earnings Per Share (70 percent weight) • Safety (12 percent weight), and • Strategic Initiatives (18 percent weight). • To align executive officers' efforts with the Company's performance objectives.	• Annual incentive targets were established by the HR Committee based on compensation information provided in Meridian's annual study. • Operating earnings per share was chosen as the primary performance measure for 2017. • The CEO's award was determined by the independent directors, and the other named executive officers' awards were determined by the HR Committee.
Long-Term Incentive Compensation	• To motivate AEP management to create sustainable shareholder value by linking a substantial portion of their potential compensation directly to longer-term shareholder returns. • To help ensure that Company management remains focused on longer-term results, which the HR Committee considers essential given the large amount of long-term investment in physical assets required in our business. • To reduce executive turnover and maintain management consistency.	• For 2017, the HR Committee granted 75 percent of the long-term incentive awards in the form of three-year performance units and 25 percent in the form of restricted stock units. • Long-term incentive award opportunities for named executive officers are based on market data from Meridian's annual study. • For the 2017-2019 performance unit awards, the HR Committee established the following equally weighted performance measures: • Three-year cumulative operating earnings per share relative to a target approved by the HR Committee, and • Three-year total shareholder return relative to AEP's Compensation Peer Group.

Base Salary. The HR Committee determines base salary increases for our named executive officers based on the following factors:

- The performance of the executive during the previous year;
- The market competitiveness of the executive's salary, total cash compensation and total compensation;
- The Company's salary increase budgets;
- The current scope and responsibilities of the position;
- Internal comparisons; and
- The experience and future potential of each executive.

The HR Committee approved base salary increases for 2017 of approximately 3 percent for each of our named executives.

Annual Incentive Compensation

Target Opportunity. The HR Committee establishes the annual incentive target opportunities for each executive officer position based on market competitive compensation as shown in Meridian's annual executive compensation survey. For 2017, the HR Committee established the following annual incentive target opportunities:

- 130 percent of base earnings for the Chairman, President & Chief Executive Officer (Mr. Akins);
- 80 percent of base earnings for the EVP & Chief Financial Officer (Mr. Tierney);
- 70 percent of base earnings for the EVP, General Counsel and Secretary (Mr. Feinberg);
- 70 percent of base earnings for the EVP Transmission (Ms. Barton); and
- 70 percent of base earnings for the EVP & Chief Administrative Officer (Ms. Hillebrand).

Performance Metrics. The HR Committee approved a balanced scorecard which tied annual incentive awards to the Company's operating earnings, safety and strategic objectives for the year and which are critical to the Company's long-term success. The HR Committee used a balanced scorecard because it helps mitigate the risk that executives will focus on one or a few objectives, such as short-term financial performance, to the detriment of other objectives. For 2017, the HR Committee approved the following performance measures:

Operating Earnings per Share (70 Percent). The HR Committee chose operating earnings per share because it largely reflects management's performance operating the Company and is strongly correlated with shareholder returns. In addition, operating earnings per share is the primary measure by which the Company communicates its actual and expected future financial performance to the investment community and employees. Management and the HR Committee believe that sustainable operating earnings per share growth is the primary means for the Company to create long-term shareholder value. In 2017, the HR Committee established an operating earnings per share target of $3.70 to incentivize the Company's strategic transformation to a higher cumulative annual growth rate versus previous years.

Safety (12 Percent). Safety is a core value and therefore maintaining the safety of AEP employees, contractors and the general public is always a primary consideration. The 2017 safety metrics consisted of the following:

- 7 percent for DART improvement. DART is an acronym for Days Away, Restricted or Job Transfer and is an industry accepted measure that focuses on more serious injuries.

- 3 percent for a fatality measure. 1.5 percent was an employee fatality measure and 1.5 percent was a contractor fatality measure.

- 1 percent for environmental stewardship. This measure was based on the number of significant environmental enforcement actions that were resolved during the year.

- 1 percent for NERC violations. This metric was based on the percentage of self-reported North American Electric reliability (NERC) violations. NERC establishes the reliability standards for planning and operating the North American bulk power system.

Strategic Initiatives (18 Percent). The strategic initiatives consisted of:

- 8 percent for Business Transformation initiatives, including measures based on the volume of start-up projects of our competitive subsidiaries focused on building renewable power projects and measures that were based on expanding the Company's transmission business.

- 6 percent for Customer Experience initiatives, including measures based on the reliability of our wires assets, residential customer satisfaction survey results and the success of our mobile alert program.

- 4 percent for Culture and Employee Engagement initiatives, including a culture measure for improvements in our employee survey results, and a diversity measure based on improvement in female and minority representation rates in the Company's employee population.

The chart below shows the weightings for each performance measure as a percentage of the total award opportunity, the threshold, target and maximum performance goals, 2017 actual results and related weighted scores.

	Weight	Threshold	Target	Maximum	Actual Performance Result	Actual Award Score (as a percent of target opportunity)	Weighted Score
Operating Earnings Per Share (70%)	70%	$3.55	$3.70	$4.00	$3.68	83.9%	0.587
Safety (12%)							
DART (Days Away, Restricted or Job Transfer) Rate, an industry measure focused on serious injuries	7%	0 percent Improvement	10 percent Improvement	20 percent Improvement	2 percent	20.0%	0.014
Fatality Measure (the number of fatal work related employee incidents)	1.5%	One or more	-	None	No employee fatality	200.0%	0.030
Fatality Measure (the number of fatal work related contractor incidents)	1.5%	One or more	-	None	Two contractor fatalities	0.0%	0.000
Environmental Stewardship – Number of significant enforcement actions	1%	4	2	0	1	150.0%	0.015
NERC Compliance – Percentage of NERC violations self-reported	1%	80%	90%	100%	95.4%	154.0%	0.015
Strategic Initiatives (18%)							
Business Transformation Measures (8%)							
Volume of AEP OnSite Partners investment commitment	2%	$75 million	$125 million	$175 million	$142.7 million	135.4%	0.027
Volume AEP Renewables investment commitment	2%	$100 million	$300 million	$400 million	$382.5 million	182.5%	0.037
Volume of Transmission Plant in Service	2%	$2.0 billion	$2.1 billion	$2.3 billion	$2.507 billion	200.0%	0.040
Volume of Transmission Capital Investment	2%	$2.79 billion	$2.94 billion	$3.23 billion	$3.43 billion	200.0%	0.040
Customer Experience Measures (6%)							
Wires Reliability- measure based on a customer weighted average of SAIDI (System Average Incident Duration Index) Performance Scores of AEP operating companies	2%	Generally 120 percent of target	Regulatory targets or a glide path to the regional peer group average	Generally 80 percent of target	105.6% Average Operating Company Score	105.6%	0.021
Customer Satisfaction – measure based on a weighted average of J.D. Power Residential Customer Satisfaction Index scores for AEP operating companies	2%	No improvement	Peer Group improvement rate	Top quartile Customer Satisfaction score	92.1% Average Operating Company Score	92.1%	0.018
Mobile Alert Penetration for Customers	2%	Current penetration	25% Customer penetration	38% Customer penetration	47% Customer Penetration	200.0%	0.040
Culture and Employee Engagement Measures (4%)							
Employee Engagement – based on improvement in average overall score of survey of AEP employees	2%	0.06 improvement	0.10 improvement	0.20 improvement	0.08 Improvement	50.0%	0.010
Employee Diversity – measure based on increased representation of women and minorities in all EEO categories	2%	Higher of 0 percent attrition plus hiring at 80 percent of target or 0 percent improvement	Higher of 0 percent attrition plus hiring at 100 percent of target or 0 percent improvement	Higher of 0 percent attrition plus hiring at 120 percent of target or 0 percent improvement	Female Representation Score: 132.3% Minority Representation Score: 130.9%	131.6%	0.026
Total Score							**0.920**

2017 Individual Award Calculations. Based on the results under the Scorecard, the HR Committee approved a weighted score of 92.0 percent. The HR Committee then subjectively evaluated the individual performance of each named executive officer to determine the actual award payouts. The HR Committee considered the progress made during 2017 focusing the Company on its core regulated businesses for Mr. Akins.

Name	2017 Base Earnings*		Annual Incentive Target %		Weighted Score Under Performance Score Card		Calculated Annual Incentive Opportunity	2017 Actual Payouts
Mr. Akins	$1,372,885	x	130%	x	92.0%	=	$1,641,970	$1,700,000
Mr. Tierney	$749,154	x	80%	x	92.0%	=	$551,377	$555,000
Mr. Feinberg	$631,269	x	70%	x	92.0%	=	$406,537	$406,000

Ms. Barton	$549,231	x	70%	x	92.0%	=	$353,705	$356,000
Ms. Hillebrand	$576,346	x	70%	x	92.0%	=	$371,167	$375,000

* Based on salary paid in 2017, which is slightly different than the salary earned for 2017 shown in the Summary Compensation Table.

Long-Term Incentive Compensation

The HR Committee grants long-term incentive compensation to executive officers on an annual award cycle. The HR Committee establishes target long-term incentive award opportunities for each named executive officer based on market data provided in the annual Meridian survey. AEP annually reviews the mix of long-term incentive compensation provided to its executives. For 2017 the HR Committee approved the following mix of long-term incentive awards:

- 75 percent of the long-term incentives was awarded as three-year performance units, and
- 25 percent of the long-term incentives was awarded as time-vesting restricted stock units (RSUs).

2017 Long-Term Incentive Awards

Name		Target Value (1)	Total Number of Units Granted (2)	Number of Performance Units Granted (at Target)	Number of RSUs Granted
Mr. Akins	$	7,500,000	116,986	87,740	29,246
Mr. Tierney	$	2,000,000	31,196	23,397	7,799
Mr. Feinberg	$	1,200,000	18,718	14,039	4,679
Ms. Barton	$	1,200,000	18,718	14,039	4,679
Ms. Hillebrand	$	950,000	14,818	11,114	3,704

(1) The Target Value differs from the Grant Date Fair Value shown in the Stock Award column in the Summary Compensation Table because the performance units contain a market condition (the relative TSR measure) which results in a Grant Date Fair Value for financial accounting purposes that differs from the target value the HR Committee used to determine the awards. See footnote 2 to the Summary Compensation Table for a description of the Grant Date Fair Value.

(2) The total number of units granted was determined by dividing the Target Value by the closing price of AEP common stock on the grant date ($64.11) and rounding to the nearest whole number.

Performance Units. Each performance unit has an economic value equivalent to one share of AEP common stock. AEP grants performance units at the beginning of each year with a three-year performance and vesting period.

Dividends are reinvested in additional performance units that are subject to the same performance measures and vesting requirements as the underlying performance units on which they were granted. The total number of performance units held at the end of the performance period is multiplied by the equally weighted score for the two performance measures shown below to determine the number of performance units earned. The maximum score for each performance measure is 200 percent.

Performance Measures for 2017 - 2019 Performance Units

Performance Measure	Weight	Threshold Performance	Target Performance	Maximum Payout Performance
3-Year Cumulative Operating Earnings Per Share	50%	$11.206 (25% payout)	$11.78 (100% payout)	$12.646 (200% payout)
3-Year Total Shareholder Return of AEP vs. AEP's Compensation Peer Group	50%	20th Percentile (0% payout)	50th Percentile (100% payout)	80th Percentile (200% payout)

The HR Committee selected a measure of cumulative operating earnings to ensure that earnings for all three years contribute equally to the award calculation. The HR Committee also selected a total shareholder return measure for these awards to provide an external performance comparison that reflects the effectiveness of management's strategic decisions and actions over the three-year performance period relative to other large electric utilities.

Restricted Stock Units. Each RSU has an economic value equivalent to one share of AEP common stock. RSUs vest over a forty month period from their January 1, 2017 effective date, subject to the executive's continued employment, in three approximately equal installments on May 1, 2018, May 1, 2019 and May 1, 2020. Dividends are reinvested in additional RSUs and are subject to the same vesting requirements applicable to the underlying RSUs on which they were granted.

Stock Ownership Requirements. The HR Committee believes that linking a significant portion of the named executive officers' financial rewards to the Company's long-term success gives executives a stake similar to that of the Company's shareholders and encourages management strategies that benefit shareholders. Therefore, the HR Committee requires certain officers (55 individuals as of January 1, 2018) to accumulate and hold a specific amount of AEP common stock or stock equivalents. The CEO's stock ownership requirement is six times his base salary, and the other named executive officers' targets are three times their respective base salaries. Each named executive officer met his or her stock ownership requirement as of March 1, 2018.

Equity Retention (Holding Period). Until an executive officer meets his or her stock ownership requirement, performance units awarded under the Long-term Incentive Plan are mandatorily deferred into AEP Career Shares to the extent necessary to meet their stock ownership requirement. If an executive has not met his or her stock ownership requirement within five years of the date it became effective or subsequently falls below it, the HR Committee may require the executive to defer a portion of his or her annual incentive compensation award into AEP Career Shares. AEP Career Shares are not paid to executives until after their employment with AEP ends.

Benefits. AEP generally provides the same health and welfare benefits to named executive officers as it provides to other employees. AEP also provides the named executive officers with either four or five weeks of paid vacation, depending on their length of service and position.

The named executive officers participate in the same tax-qualified defined benefit pension plan and defined contribution savings plan as other eligible employees. They also participate in the Company's non-qualified retirement benefit plans, which largely provide "excess benefits" that would otherwise be offered through the tax-qualified plans but for IRS limits. This allows the named executive officers to accumulate replacement income for their retirement based on the same benefit formulas as the tax qualified plans but without the limitations that are imposed by the Internal Revenue Code on the tax-qualified plans.

The HR Committee recognizes that the non-qualified plans result in the deferral of the Company's income tax deduction related to these benefits until such benefits are paid. However, the HR Committee

believes that executives generally should be entitled to the same retirement benefits, as a percentage of their eligible pay, as the Company's other employees. Non-qualified retirement benefit plans are also prevalent among large employers both within our industry and other large U.S. industrial companies, and are provided as part of a market competitive total rewards package.

The Company limits both the amount and types of compensation that are included in the qualified and non-qualified retirement plans because the HR Committee and AEP management believe that compensation over certain limits and certain types of compensation should not be further enhanced by including it in retirement benefit calculations. Therefore:

- Long-term incentive compensation is not included in the calculations that determine retirement and other benefits under AEP's benefit plans,

- The cash balance formula of the Company’s non-qualified pension plan (the “AEP Supplemental Benefit Plan”) limits eligible compensation to twice the executive’s base salary, and

- Eligible compensation is also limited to $2 million under the non-qualified Supplemental Retirement Savings Plan.

AEP provides group term life insurance benefits to all employees, including the named executive officers, in the amount of two times their base salary.

For all employees, including the executives, whom the Company asks to relocate, it is AEP’s practice to offer relocation assistance to offset their moving expenses. This policy better enables AEP to obtain high quality new hires and to relocate internal job candidates.

Perquisites. The HR Committee annually reviews the perquisites provided by the Company. In 2017, AEP provided independent financial counseling and tax preparation services to assist executives with financial planning and tax filings. Income is imputed to executives and taxes are withheld for these services.

The HR Committee is sensitive to concerns regarding the expense of corporate aircraft and the public perception regarding personal use of such aircraft. Accordingly, the HR Committee generally prohibits personal use of corporate aircraft that has an incremental cost to the Company. The Company allows personal travel on business trips using the corporate aircraft if there is no incremental cost to the Company. Income is imputed and taxes are withheld on the value of personal travel on corporate aircraft in accordance with IRS guidelines.

Other Compensation Information

Recoupment of Incentive Compensation. The Company’s Policy on Recouping Incentive Compensation, commonly referred to as a “clawback” policy, provides that our executive officers and certain other senior executives are subject to a ‘no fault’ clawback. The Board may recover incentive compensation whether or not the executive’s actions involve misconduct. The Board believes, subject to the exercise of its discretion based on the facts and circumstances of a particular case, that incentive compensation should be reimbursed to the Company if, in the Board’s determination:

- Such incentive compensation was received by an executive where the payment or the award was predicated upon the achievement of financial or other results that were subsequently materially restated or corrected, and

- Such incentive compensation would have been materially lower had the achievement been calculated on such restated or corrected financial or other results.

The HR Committee has directed the Company to design and administer all of its incentive compensation programs in a manner that provides for the Company’s ability to obtain such reimbursement. AEP may also retain any deferred compensation previously credited to an executive. This right to reimbursement is in addition to, and not in substitution for, any and all other rights AEP might have to pursue reimbursement or such other remedies against an executive for misconduct.

Role of the CEO and Compensation Consultant in Determining Executive Compensation. The HR Committee invites the CEO to attend HR Committee meetings. The HR Committee regularly holds executive sessions without management present.

The CEO has assigned AEP’s Executive Vice President & Chief Administrative Officer and AEP’s Director - Compensation and Executive Benefits to support the HR Committee. These individuals work closely with the HR Committee Chairman, the CEO and Meridian to research and develop requested information, prepare meeting materials, implement the HR Committee’s actions and administer the Company’s executive compensation and benefit programs consistent with the objectives established by the HR Committee. Meetings are held with the CEO, the HR Committee Chairman and Meridian prior to HR Committee meetings to review and finalize the agenda and meeting materials.

The CEO regularly discusses his strategic vision and direction for the Company during HR Committee meetings with Meridian in attendance. Likewise, Meridian regularly discusses compensation strategy alternatives, in light of the CEO's strategic vision and direction, during HR Committee meetings with the CEO in attendance. The HR Committee believes that this open dialogue and exchange of ideas is important to the development and implementation of a successful executive compensation strategy.

The CEO discusses the individual performance of the other named executive officers with the HR Committee and recommends their compensation to the HR Committee. The CEO has substantial input into salary budgets and changes to incentive targets. The CEO also has substantial input into the development of employment offers for outside candidates for executive positions, although the HR Committee must approve all employment offers for executive officers.

Change In Control Agreements. The HR Committee provides Change In Control agreements to specified executives, including all the named executive officers. While the HR Committee believes these agreements are consistent with the practices of its peer companies, the most important reason for these agreements is to protect the Company and the interests of shareholders in the event of an anticipated or actual change in control. During such transitions, retaining and continuing to motivate the Company's key executives would be critical to protecting shareholder value. In a change of control situation, outside competitors are more likely to try to recruit top performers away from the Company, and our executive officers may consider other opportunities when faced with uncertainty about retaining their positions. The HR Committee limits participation to those executives whose full support and sustained contributions would be needed during a lengthy and complex corporate transaction.

The Board has adopted a policy that requires shareholder approval of executive severance agreements that provide benefits generally exceeding 2.99 times the sum of the named executive officer's salary plus annual incentive compensation. The HR Committee periodically reviews change in control agreement practices of companies in our Compensation Peer Group. The HR Committee has approved change in control multiples of 2.99 times base salary and annual incentive compensation for each of the named executive officers, which is consistent with competitive market practice. Each agreement includes a "double trigger," which means that severance payments and benefits would be provided to the covered executive officer only upon a change in control accompanied by an involuntary termination or constructive termination within two years after the change in control.

The Company's Change In Control agreements do not provide a tax gross-up for excise taxes.

Long-term incentive compensation may also vest in the event of a change in control. All outstanding performance units and RSU awards have a double trigger change in control provision. In the event an executive's employment is terminated within one year after a change in control under qualifying conditions, such as by the Company without cause or by the executive for good reason, then all of the executive's outstanding performance units and RSUs will vest. Performance units would be paid at the target performance score.

Other compensation and benefits provided to executive officers in the event their employment is terminated as a result of a change in control are consistent with that provided in the event an executive's employment is terminated due to a consolidation, restructuring or downsizing as described below.

Other Employment Separations. The Company has an Executive Severance Plan that provides severance benefits to selected senior officers of the Company, including the named executive officers, who agree to its terms, including confidentiality, non-solicitation, cooperation and non-disparagement obligations. Executives remain eligible for benefits under the general severance plan described below; however, any benefits provided under the Executive Severance Plan would be reduced by any amounts provided under the general severance plan. Benefits for our named executive officers under the Executive Severance Plan (which would be triggered by a good reason resignation or an involuntary termination) include pay continuation of two times their base salary and target annual incentive award payable over two years, and are conditioned on the executive officer's release of claims against the Company and agreement not to compete with the Company for two years.

AEP also maintains a broad-based severance plan that provides two weeks of base pay per year of service to all employees, including named executive officers, if their employment is terminated due to a consolidation, restructuring or downsizing, subject to the employee's agreement to waive claims against AEP. In addition, our severance benefits for all employees include outplacement services and access to health benefits at active employee rates for up to 18 months and then at Company-subsidized retiree rates thereafter until age 65 for employees who are at least age 50 with 10 years of service at the time of their employment termination.

Named executive officers remain eligible for an annual incentive award based on their eligible pay for the year reflecting the portion of the year worked, if they separate from service prior to year-end due to their retirement (on or after age 55 with at least ten years of service, except employees who retire as part of a voluntary or involuntary severance program). In the event of a participant's death, this amount is paid to their estate.

A prorated portion of outstanding performance units vest if a participant retires, which is defined as a termination, other than for cause, after the executive reaches age 55 with five years of service or if a participant is severed. A prorated portion of outstanding performance units and all outstanding RSUs would also vest to a participant's heirs in the event of the participant's death. The pro-rated performance units are not payable until the end of the performance period and remain subject to all of the performance objectives.

Executive officers were also entitled to 12 months of continued financial counseling service in the event they are severed from service as the result of a restructuring, consolidation or downsizing or they retire (after age 55 and 5 years of AEP service). In the event of their death, their spouse or the executor of their estate would be eligible for this benefit.

Insider Trading, Hedging and Pledging. The Company's insider trading policy prohibits directors and executive officers from hedging their AEP stock holdings through short sales and the use of options, warrants, puts and calls or similar instruments. The policy also prohibits directors and executive officers from pledging AEP stock as collateral for any loan.

Tax Considerations. Section 162(m) of the Internal Revenue Code (Section 162 (m)) limits the Company's ability to deduct compensation in excess of $1,000,000 paid in any year to the Company's named executive officers. The HR Committee adopted performance goals so that awards made pursuant to such goals that contributed to a named executive officer earning more than $1 million in annual compensation may

qualify as tax deductible to the Company for U.S. federal income tax purposes under Section 162(m). In December 2017, the U.S. federal government enacted the Tax Cuts and Jobs Act, which substantially modifies the U.S. Internal Revenue Code and, among other things, and subject to certain exceptions, eliminated the performance-based compensation exception under Section 162(m). As a result, the Company expects that, except to the extent an exception applies, any compensation over $1 million paid to any current or future named executive officer in a fiscal year will not be tax deductible. The HR Committee certified certain performance measures in December 2017 to protect a portion of the tax deduction for performance based compensation that would be paid in February and March 2018 to the Company's named executive officers.

Executive Compensation

Summary Compensation Table

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
Nicholas K. Akins—								
Chairman of the Board and Chief Executive Officer	2017	1,375,000	—	7,983,420	1,700,000	361,001	111,040	11,530,461
	2016	1,325,077	—	6,720,027	3,000,000	323,949	103,687	11,472,740
	2015	1,279,900	—	6,719,981	3,150,000	199,027	103,658	11,452,566
Brian X. Tierney—								
Executive Vice President and	2017	750,000	—	2,128,899	555,000	462,223	98,262	3,994,384
Chief Financial Officer	2016	730,800	—	1,895,038	990,000	131,575	95,026	3,842,439
	2015	709,246	—	1,907,216	1,100,000	0	84,125	3,800,587
David M. Feinberg—								
Executive Vice President,	2017	632,000	—	1,277,372	406,000	104,619	73,347	2,493,338
General Counsel and Secretary	2016	615,358	—	1,126,919	730,000	85,179	75,435	2,632,891
	2015	591,426	—	998,394	800,000	59,069	68,163	2,517,052
Lisa M. Barton—								
Executive Vice President- Transmission	2017	550,000	—	1,277,372	356,000	110,304	67,724	2,361,400
	2016	532,039	—	1,003,030	650,000	95,020	68,007	2,348,096
	2015	516,750	—	998,394	686,000	49,931	59,042	2,310,117
Lana L. Hillebrand—								
Executive Vice President- Chief	2017	577,000	—	1,011,219	375,000	193,929	69,817	2,226,965
Administrative Officer	2016	562,154	—	902,677	670,000	139,726	73,753	2,438,310
	2015	545,530	—	902,420	749,000	101,326	62,382	2,351,658

(1) Amounts in the salary column are composed of executive salaries earned for the year shown.

(2) The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance units and restricted stock units (RSUs) granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2017 for a discussion of the relevant assumptions used in calculating these amounts. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance units, plus any dividend equivalents.

The value of the performance units granted in 2017 will be based on two equally weighted measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS) and a total shareholder return measure (Relative TSR). The grant date fair value of the 2017 performance units that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 based upon the probable outcome of the performance conditions as of the grant date. Assuming the highest level of performance achievement as of the grant date, the aggregate grant date fair value of the Cumulative EPS awards would have been: $5,625,011 for Mr. Akins; $1,499,982 for Mr. Tierney; $900,040 for Mr. Feinberg; $900,040 for Ms. Barton and $712,519 for Ms. Hillebrand. As the performance units that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they had no maximum grant date fair values that differed from the grant date fair values presented in the table.

The performance units granted in 2017 were changed to settle in AEP shares, rather than cash, as was the case for the performance units granted in 2015 and 2016. Because the 2017 performance units are to be settled in AEP shares and the Relative TSR measure is a market condition, the maximum value is factored into the calculation of the grant date fair value. The grant date fair value of the 2017 performance units is approximately 8.6 percent higher due to the accounting impact of the change in settling the performance units in AEP shares rather than cash.

The maximum amount payable for the 2016 performance units is equal to $10,080,010 for Mr. Akins; $2,842,526 for Mr. Tierney; $1,690,378 for Mr. Feinberg; $1,504,608 for Ms. Barton and $1,353,984 for Ms. Hillebrand. The RSUs vest over a forty month period from their January 1 effective date. For further information on these awards, see the Grants of Plan-Based Awards for 2017 table.

(3) The amounts shown in this column are annual incentive compensation paid. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits for 2017 table, and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements

included in our Form 10-K for the year ended December 31, 2017 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

(5) Amounts shown in the All Other Compensation column for 2017 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan and (c) perquisites. The amounts are listed in the following table:

Type	Nicholas K. Akins	Brian X. Tierney	David M. Feinberg	Lisa M. Barton	Lana L. Hillebrand
Retirement Savings Plan Match	$ 11,804	$ 12,150	$ 12,150	$ 12,150	$ 12,150
Supplemental Retirement Savings Plan Match	$ 77,850	$ 66,112	$ 49,107	$ 41,815	$ 43,936
Perquisites	$ 21,386	$ 20,000	$ 12,090	$ 13,759	$ 13,731
Total	**$ 111,040**	**$ 98,262**	**$ 73,347**	**$ 67,724**	**$ 69,817**

Perquisites provided in 2017 included: financial counseling and tax preparation services, and, for Mr. Akins, director's accidental death insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time executive officers may receive customary gifts from third parties that sponsor sporting events (subject to our policies on conflicts of interest).

Grants of Plan-Based Awards for 2017

The following table provides information on plan-based awards granted in 2017 to each of our named executive officers.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1) Threshold ($)	Target ($)	Maximum ($)(2)	Estimated Future Payouts Under Equity Incentive Plan Awards(3) Threshold (#)(4)	Target (#)	Maximum (#)(5)	All Other Stock Awards: Number of Shares of Stock or Units (#)(6)	Grant Date Fair Value of Stock and Option Awards ($)(7)
Nicholas K. Akins									
2017 Annual Incentive Compensation Plan		—	1,784,751	4,461,878					
2017 – 2019 Performance Units	2/20/17				10,968	87,740	175,480		6,108,459
Restricted Stock Units	2/20/17							29,246	1,874,961
Brian X. Tierney									
2017 Annual Incentive Compensation Plan		—	599,323	1,498,308					
2017 – 2019 Performance Units	2/20/17				2,925	23,397	46,794		1,628,905
Restricted Stock Units	2/20/17							7,799	499,994
David M. Feinberg									
2017 Annual Incentive Compensation Plan		—	441,888	1,104,720					
2017 – 2019 Performance Units	2/20/17				1,755	14,039	28,078		977,401
Restricted Stock Units	2/20/17							4,679	299,971
Lisa M. Barton									
2017 Annual Incentive Compensation Plan		—	384,462	961,155					
2017 – 2019 Performance Units	2/20/17				1,755	14,039	28,078		977,401
Restricted Stock Units	2/20/17							4,679	299,971
Lana L. Hillebrand									
2017 Annual Incentive Compensation Plan		—	403,442	1,008,605					
2017 – 2019 Performance Units	2/20/17				1,389	11,114	22,228		773,756
Restricted Stock Units	2/20/17							3,704	237,463

(1) Represents potential payouts under the 2017 Annual Incentive Compensation Plan (ICP), which are based on base earnings paid during the year.
(2) The amounts shown in this column represent 250 percent of the target award for each of the named executive officers, which is the maximum amount generally payable to any individual employee under the ICP.
(3) Represents performance units awarded under our Long-Term Incentive Plan for the 2017-2019 performance period. These awards generally vest at the end of the three year performance period based on our attainment of specified performance measures. The number of performance units does not include additional units that may accrue as dividends.
(4) The amounts shown in the Threshold column represent 12.5% of the target award for each of the named executive officers because the Operating Earnings per Share measure has a 25% payout for threshold performance, the Total Shareholder Return measure has a 0% payout for threshold performance and these measures are equally weighted. However, the Operating Earnings per Share threshold does not guarantee a minimum payout because the score would be 0% of target if threshold performance is not achieved.
(5) The amounts shown in this column represent 200 percent of the target award for each of the named executive officers, which is the maximum overall score for the 2017-2019 performance units.
(6) Represents restricted stock units awarded under the Long-Term Incentive Plan. These awards generally vest in three equal installments on May 1, 2018, May 1, 2019 and May 1, 2020. The number of restricted stock units does not include additional units that may accrue as dividends.
(7) Amounts represent the grant date fair value of performance units and restricted stock units measured in accordance with FASB ASC Topic 718, utilizing the assumptions discussed in Note 15 to our consolidated financial statements for the fiscal year ended December 31, 2017. The actual number of performance units earned will depend on AEP's performance over the 2017 through 2019 period, which could vary

from 0 percent to 200 percent of the target award plus dividends. The value of the performance units granted in 2017 will be based on two equally weighted measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS) and a total shareholder return measure (Relative TSR). The grant date fair value of the 2017 performance units that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 based upon the probable outcome of the performance conditions as of the grant date. The performance units that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718. The performance units granted in 2017 were changed to settle in AEP shares, rather than cash, as was the case for the performance units granted in 2015 and 2016. Because the 2017 performance units are to be settled in AEP shares and the Relative TSR measure is a market condition, the maximum value is factored into the calculation of the grant date fair value.

Outstanding Equity Awards at Fiscal Year-End for 2017

The following table provides information with respect to holdings of restricted stock units and performance units by the named executive officers at December 31, 2017. The named executive officers do not have any outstanding stock options.

	Stock Awards			
	Number of Shares or Units of	Market Value of Shares or Units of Stock That	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or

Name	Stock That Have Not Vested (#)	Have Not Vested ($)	Have Not Vested (#)(1)	Other Rights That Have Not Vested ($)(2)
Nicholas K. Akins				
2016 - 2018 Performance Units(3)			172,004	12,654,334
2017 - 2019 Performance Units(3)			179,764	13,225,237
2015 Restricted Stock Units(4)	12,627	928,968		
2016 Restricted Stock Units(5)	19,112	1,406,070		
2017 Restricted Stock Units(6)	29,960	2,204,157		
Brian X. Tierney				
2016 - 2018 Performance Units(3)			48,504	3,568,439
2017 - 2019 Performance Units(3)			47,936	3,526,652
2015 Restricted Stock Units(4)	3,585	263,748		
2016 Restricted Stock Units(5)	5,390	396,542		
2017 Restricted Stock Units(6)	7,989	587,751		
David M. Feinberg				
2016 - 2018 Performance Units(3)			28,844	2,122,053
2017 - 2019 Performance Units(3)			28,764	2,116,167
2015 Restricted Stock Units(4)	1,877	138,091		
2016 Restricted Stock Units(5)	3,205	235,792		
2017 Restricted Stock Units(6)	4,793	352,621		
Lisa M. Barton				
2016 - 2018 Performance Units(3)			25,674	1,888,836
2017 - 2019 Performance Units(3)			28,764	2,116,167
2015 Restricted Stock Units(4)	1,877	138,091		
2016 Restricted Stock Units(5)	2,853	209,895		
2017 Restricted Stock Units(6)	4,793	352,621		
Lana L. Hillebrand				
2016 - 2018 Performance Units(3)			23,104	1,699,761
2017 - 2019 Performance Units(3)			22,770	1,675,189
2015 Restricted Stock Units(4)	1,697	124,848		
2016 Restricted Stock Units(5)	2,568	188,928		
2017 Restricted Stock Units(6)	3,794	279,125		

(1) Pursuant to applicable SEC rules, the number of performance units reported in this column is the maximum number of performance units issuable (200% of the amount outstanding at December 31, 2017) because the results

for the performance units that vested on December 31, 2017 were above target. However, the actual number of performance units credited upon vesting will be based on AEP's actual performance over the applicable three-year period.

(2) Pursuant to applicable SEC rules, the market value of the performance units reported in this column was computed by multiplying the closing price of AEP's common stock on December 31, 2017 ($73.57) by the maximum number of performance units issuable set forth in the preceding column because the results for the performance units that vested on December 31, 2017 were above target. However, the actual number of performance units credited upon vesting will be based on AEP's actual performance over the applicable three-year period.

(3) AEP's practice is to grant performance units at the beginning of each year with a three-year performance and vesting period. This results in awards for overlapping successive three-year performance periods. These awards generally vest at the end of the three year performance period. The performance units awarded for the 2015 - 2017 performance period, including associated dividend credits, vested at December 31, 2017 and are shown in the Options Exercises and Stock Vested for 2017 table below. The awards shown for the 2016 - 2018 and 2017 - 2019 performance periods include performance units resulting from reinvested dividends which are subject to the same performance criteria.

(4) These restricted stock units were granted on February 24, 2015 and will generally vest, subject to the executive officer's continued employment, on May 1, 2018. The amounts shown include restricted stock units resulting from reinvested dividends.

(5) These restricted stock units were granted on February 23, 2016 and will generally vest, subject to the executive officer's continued employment, in two equal installments, on May 1, 2018 and May 1, 2019. The amounts shown include restricted stock units resulting from reinvested dividends.

(6) These restricted stock units were granted on February 20, 2017 and will generally vest, subject to the executive officer's continued employment, in three equal installments, on May 1, 2018, May 1, 2019 and May 1, 2020. The amounts shown include restricted stock units resulting from reinvested dividends.

Option Exercises and Stock Vested for 2017

The following table provides information with respect to the vesting of RSUs and performance units in 2017 that were granted to our named executive officers in previous years. The named executive officers did not exercise any stock options in 2017.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)(1)	Value Realized on Vesting ($) (2)
Nicholas K. Akins	—	—	183,764	$13,287,138
Brian X. Tierney	—	—	52,074	$3,765,626
David M. Feinberg	—	—	27,392	$1,980,155
Lisa M. Barton	—	—	26,834	$1,942,506
Lana L. Hillebrand	—	—	24,664	$1,783,408

(1) This column includes the following performance units and related dividend equivalents for the 2015 - 2017 performance period that vested on December 31, 2017: 145,669 for Mr. Akins; 41,343 for Mr. Tierney; 21,642 for Mr. Feinberg; 21,642 for Ms. Barton; and 19,562 for Ms. Hillebrand. This column also includes the following RSUs that vested on May 1, 2017: 38,095 for Mr. Akins; 10,731 for Mr. Tierney; 5,750 for Mr. Feinberg; 5,192 for Ms. Barton; and 5,102 for Ms. Hillebrand.

(2) As is required, the value included in this column for the 2015-2017 performance units is computed by multiplying the number of units by the closing price of AEP's common stock on the vesting date of December 31, 2017 ($73.57). However, the actual value realized from these units was based on the 20-day average closing market price of AEP common stock prior to the vesting date ($75.448). Also as required, this column includes the value of RSUs that vested on May 1, 2017 computed by multiplying the number of units vesting by the closing price of AEP's common stock on this date, which was $67.47 per share. However, the actual value realized from these units was based on the 20-day average closing market price of AEP common stock prior to the vesting date ($67.64).

2015 - 2017 Performance Units

Performance units that were granted for the 2015 - 2017 performance period vested on December 31, 2017. The combined score for the 2015-2017 performance period was 164.8 percent of target. The final score calculation for these performance measures is shown in the chart below.

Performance Measures	Threshold Performance	Target Performance	Maximum Payout Performance	Actual Performance	Score	Weight	Weighted Score
3-Year Cumulative Earnings Per Share	$10.184 (30% payout)	$10.950 (100% Payout)	$11.717 (200% Payout)	$11.304	146.2%	50%	73.1%
3-Year Total Shareholder Return vs. S&P Electric Utilities	20th Percentile (0% Payout)	50th Percentile (100% Payout)	80th Percentile (200% Payout)	75th Percentile	183.3%	50%	91.7%
Composite Result							**164.8%**

Pension Benefits for 2017

The following table provides information regarding the pension benefits for our named executive officers under AEP's pension plans. The material terms of the plans are described following the table.

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit($)(1)	Payments During Last Fiscal Year($)
Nicholas K Akins	AEP Retirement Plan	35.6	650,217	—
	CSW Executive Retirement Plan	35.6	1,654,552	—
Brian X. Tierney	AEP Retirement Plan	19.7	405,777	—
	AEP Supplemental Benefit Plan	19.7	1,396,224	—
David M. Feinberg	AEP Retirement Plan	6.7	103,015	—
	AEP Supplemental Benefit Plan	6.7	294,407	—
Lisa M. Barton	AEP Retirement Plan	11.1	182,695	—
	AEP Supplemental Benefit Plan	11.1	291,135	—
Lana L. Hillebrand	AEP Retirement Plan	22.6 (2)	532,931	—
	AEP Supplemental Benefit Plan	22.6	326,724	—

(1) The Present Value of Accumulated Benefits is based on the benefit accrued under the applicable plan through December 31, 2017, and the following assumptions (which are consistent with those used in AEP's financial statements):

- The named executive officer retires at normal retirement age (age 65), except for Mr. Tierney, whose benefit is calculated at age 62 because he is eligible for an unreduced annuity benefit when he reaches that age.

- The named executive commences the payment of benefits (the "accrued benefit") immediately upon retirement.

- The value of the annuity benefit at the named executive officer's assumed retirement age is determined based upon the accrued benefit, an assumed interest rate of 3.65 percent, 3.45 percent and 3.45 percent for the benefits accrued under the AEP Retirement Plan, AEP Supplemental Benefit Plan and the CSW Executive Retirement Plan, respectively, and assumed mortality based upon modified versions of the RP-2014 mortality tables. Base mortality rates are derived from the RP-2014 table factored to 2006 with no collar adjustment for the qualified pension benefits and a white collar adjustment for non-qualified pension benefits. Mortality improvements are projected generationally using the MP-2017 mortality projection scale with long-term improvement rates multiplied by 0.75. The value of the lump sum benefit at that assumed retirement age is determined based upon the accrued benefit, an assumed interest rate of 3.40 percent and assumed mortality based on current law IRS lump sum mortality with static mortality projections estimated to the date of retirement using mortality projection scale MP-2017. The present value of each named executive officer's benefits is determined by discounting the value of benefits described above at the assumed retirement age to each executive's current age using an assumed interest rate of 3.65 percent, 3.45 percent and 3.45 percent for the benefits accrued under the AEP Retirement Plan, AEP Supplemental Benefit Plan and CSW Executive Retirement Plan, respectively.

- For the AEP Retirement Plan, the present value of the accrued benefit is weighted based on 75 percent lump sum and 25 percent annuity based on the assumption that participants elect those benefit options in that proportion. For the AEP Supplemental Benefit Plan and the CSW Executive Retirement Plan, the present value of the accrued benefits is weighted based on 100 percent lump sum.

(2) The benefit available to Ms. Hillebrand from the AEP Retirement Plan consists of two pieces: one under the Central and South West Corporation Cash Balance Retirement Plan (the "CSW Retirement Plan") attributable to her prior period of service between December 15, 1982 and June 30, 2000 (her "CSW Retirement Plan Benefit") and one under the cash balance formula since her return on December 17, 2012. Her CSW Retirement Plan Benefit will be paid to her either as a lump sum or in one of the annuity options offered by the plan. The amount available to her as a lump sum would be the greater of (i) her CSW Retirement Plan cash balance account ($228,531 as of December 31, 2017), or (ii) the lump sum value of her CSW Retirement Plan protected minimum normal retirement annuity (which had accrued during the 14.5 year period until her traditional pension formula benefit became frozen effective July 1, 1997), calculated using a factor based on then applicable interest and mortality assumptions as well as an assumed future cost of living adjustment rate of 3.00%. The payment available to her as an annuity would be based on the greater of (i) her CSW Retirement Plan protected minimum normal retirement annuity ($3,279 per month) or (ii) the life annuity equivalent of her then CSW Retirement Plan cash balance account, calculated using a factor based on then applicable interest and mortality assumptions.

Overview. AEP maintains tax-qualified and nonqualified defined benefit pension plans for eligible employees. The nonqualified plans provide benefits that cannot be paid under the tax-qualified plan because of maximum limitations imposed on such plans by the Internal Revenue Code. The plans are designed to provide a retirement income to executives and their spouses, as well as a market competitive benefit opportunity as part of a market competitive total rewards package.

AEP Retirement Plan. The AEP Retirement Plan is a tax-qualified defined benefit pension plan under which benefits are generally determined by reference to a cash balance formula. The AEP Retirement Plan also encompasses the Central and South West Corporation Cash Balance Retirement Plan (the "CSW Retirement Plan"), which was merged into the AEP

Retirement Plan effective December 31, 2008. As of December 31, 2017, each of the named executive officers was vested in their AEP Retirement Plan benefit.

In addition, employees who have continuously participated in the AEP Retirement Plan (but not the CSW Retirement Plan) since December 31, 2000 ("Grandfathered AEP Participants," which includes Mr. Tierney) remain eligible for an alternate pension benefit calculated by reference to a final average pay formula. The benefits under this final average pay formula were frozen as of December 31, 2010.

Cash Balance Formula. Under the cash balance formula, each participant has an account established to which dollar credits are allocated each year.

1. *Company Credits.* Each year, participants' accounts are credited with an amount equal to a percentage of their salary for that year and annual incentive award for the prior year. The applicable percentage is based on the participant's age and years of service. The following table shows the applicable percentage:

Sum of Age Plus Years of Service	Applicable Percentage
Less than 30..........	3.0%
30-39.....................	3.5%
40-49.....................	4.5%
50-59.....................	5.5%
60-69.....................	7.0%
70 or more	8.5%

Each year, the IRS calculates a limit on the amount of eligible pay that can be used to calculate pension benefits in a qualified plan. For 2017, the limit was $270,000.

2. *Interest Credits.* All amounts in the cash balance accounts earn interest at the average interest rate on 30-year Treasury securities for the month of November of the prior year, with a floor of 4 percent. For 2017, the interest rate was 4 percent.

Final Average Pay Formula. Grandfathered AEP Participants receive their benefits under the cash balance formula or the final average pay formula, whichever provides the higher benefit. On December 31, 2010, the final average pay benefit payable at the Grandfathered AEP Participant's normal retirement age was frozen, meaning that their final average pay formula benefit is not affected by the participant's service or compensation subsequent to this date. This frozen final average pay normal retirement benefit is based on the following calculation as of December 31, 2010: the participant's then years of service times the sum of (i) 1.1 percent of the participant's then high 36 consecutive months of base pay ("High 36"); plus (ii) 0.5 percent of the amount by which the participant's then High 36 exceeded the participant's applicable average Social Security covered compensation.

Grandfathered AEP Participants may become entitled to a subsidized early retirement benefit under the final average pay formula if they remain employed with AEP through age 55 with at least three years of service. The early retirement benefit payable under the final average pay formula is the unreduced normal retirement age benefit if it commences at age 62 or later. The early retirement benefit is reduced by 3 percent for each year prior to age 62 that the benefits are commenced.

AEP Supplemental Benefit Plan. The AEP Supplemental Benefit Plan is a nonqualified defined benefit pension plan. It generally provides eligible participants with benefits that are in excess of those provided under the AEP Retirement Plan (without regard to the provisions now included as the result of the merger of the CSW Retirement Plan into the AEP Retirement Plan) as determined upon the participant's termination of employment. These excess benefits are calculated under the terms of the AEP Retirement Plan described above with the following modifications: (i) annual incentive pay was taken into account for purposes of the frozen final average pay formula; and (ii) the limitations imposed by the Internal Revenue

Code on annual compensation and annual benefits are disregarded. However, eligible pay taken into account under the cash balance formula is limited to the greater of $1 million or two times the participant's year-end base salary.

Participants do not become vested in their AEP Supplemental Plan benefit until they become vested in their AEP Retirement Plan benefit or upon a change in control. As of December 31, 2017, each of the named executive officers was fully vested in their AEP Supplemental Benefit Plan benefit.

CSW Executive Retirement Plan. The CSW Executive Retirement Plan is a nonqualified defined benefit pension plan. It generally provides eligible participants with benefits that are in excess of those provided under the terms of the former CSW Retirement Plan (which was merged into the AEP Retirement Plan) as determined upon the participant's termination of employment. The excess benefits are calculated without regard to the limitations imposed by the Internal Revenue Code on annual compensation and annual benefits. As of December 31, 2017, Mr. Akins was fully vested in his CSW Executive Retirement Plan benefit.

Nonqualified Deferred Compensation for 2017

Overview. AEP maintains non-qualified deferred compensation plans that allow eligible employees, including the named executive officers, to defer receipt of a portion of their base salary, annual incentive compensation and performance unit awards. The plans are unfunded. Participants have an unsecured contractual commitment from the Company to pay the amounts due under the plans from the general assets of the Company. AEP maintains the following non-qualified deferred compensation plans for eligible employees:

- The American Electric Power System Supplemental Retirement Savings Plan (SRSP);
- The American Electric Power System Incentive Compensation Deferral Plan (ICDP); and
- The American Electric Power System Stock Ownership Requirement Plan (SORP).

The following table provides information regarding contributions, earnings and balances for our named executive officers under AEP's three non-qualified deferred compensation plans which are each further described below.

Name	Plan Name	Executive Contributions in Last FY(1) ($)	Registrant Contributions in Last FY(2) ($)	Aggregate Earnings in Last FY(3) ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE(4) ($)
Nicholas K. Akins	SRSP	103,800	77,850	47,210	—	1,828,226
	ICDP	—	—	100,436	—	426,441
	SORP	—	—	1,506,576	—	8,076,040
Brian X. Tierney	SRSP	112,380	66,112	172,039	—	3,792,456
	SORP	—	—	269,096	—	1,442,494
David M. Feinberg	SRSP	65,476	49,107	14,528	—	595,507
	SORP	—	—	449,161	—	2,407,739
Lisa M. Barton	SRSP	55,754	41,815	20,972	—	551,282
	ICDP	—	—	540	—	28,188
	SORP	—	—	340,515	—	1,825,340
Lana L. Hillebrand	SRSP	58,581	43,936	11,683	—	483,255
	SORP	140,637	—	370,831	—	2,012,484

(1) The amounts set forth under "Executive Contributions in Last FY" for the SRSP are reported in the Summary Compensation Table as either (i) Salary for 2017 or (ii) the Non-Equity Incentive Plan Compensation for 2016.

(2) The amounts set forth under "Registrant Contributions in Last FY" for the SRSP are reported in the All Other Compensation column of the Summary Compensation Table.

(3) No amounts set forth under "Aggregate Earnings in Last FY" have been reported in the Summary Compensation Table as there were no above market or preferential earnings credited to any named executive officer's account in any of the plans.

(4) The amounts set forth in the "Aggregate Balance at Last FYE" column for the SRSP include the SRSP amounts reported in the "Executive Contributions in Last FY" and "Registrant Contributions in Last FY" columns. In addition, the "Aggregate Balance at Last FYE" for the SRSP includes the following amounts previously reported in the Summary Compensation Table for prior years: $995,806 for Mr. Akins, $1,168,506 for Mr. Tierney, $435,000 for Mr. Feinberg, $99,799 for Ms. Barton and $96,946 for Ms. Hillebrand. The amounts set forth in the "Aggregate Balance at Last FYE" for the SORP include the SORP amounts reported in the "Executive Contributions in Last FY." In addition, the "Aggregate Balance at Last FYE" for the SORP includes the following amounts previously reported in the Summary Compensation Table for prior years: $2,670,419 for Mr. Akins, $5,297 for Mr. Tierney, $1,617,064 for Mr. Feinberg, and $502,170 for Ms. Barton.

Supplemental Retirement Savings Plan. This plan allows eligible participants to save on a pre-tax basis and to continue to receive Company matching contributions beyond the limits imposed by the Internal Revenue Code on qualified plans of this type.

- Participants can defer up to 50 percent of their base salary and annual incentive award in excess of the IRS' eligible compensation limit for qualified plans, $270,000 for 2017, up to $2,000,000.
- The Company matches 100 percent of the participant's contributions up to 1 percent of eligible compensation and 70 percent of the participant's contributions from the next 5 percent of eligible compensation (for a total Company match of up to 4.5% of eligible compensation).
- Participants may not withdraw any amount credited to their account until their termination of employment with AEP. Participants may elect a distribution of their account as a lump-sum or annual installment payments over a period of up to 10 years. Participants may delay the commencement of distributions for up to five years from the date of their termination of employment.
- Participants may direct the investment of their plan account among the core investment options that are available to

all employees in AEP's qualified Retirement Savings Plan and one additional option that provides interest at a rate set each December at 120 percent of the applicable federal long-term rate with monthly compounding. There were no above-market or preferential earnings with respect to the Supplemental Retirement Savings Plan's investment options in 2017.

Incentive Compensation Deferral Plan. This plan allows eligible employees to defer payment of up to 80 percent of vested performance units.

- AEP does not offer any matching contributions.
- Participants may direct the investment of their plan accounts among the core investment options that are available to all employees in AEP's qualified Retirement Savings Plan. There were no above-market or preferential earnings with respect to the Incentive Compensation Deferral Plan in 2017.
- Generally, participants may not withdraw any amount credited to their account until their termination of employment with AEP. However, participants may make one withdrawal of amounts attributable to their pre-2005 contributions prior to termination of employment. The withdrawal amount would be subject to a 10 percent withdrawal penalty. Participants may elect among the same payment options for the distributions of their account value as described above for the Supplemental Retirement Savings Plan's investment options.

Stock Ownership Requirement Plan. This plan assists executives in achieving their minimum stock ownership requirements. It does this primarily by tracking the executive's AEP Career Shares. AEP Career Shares are a form of deferred compensation, which are unfunded and unsecured general obligations of AEP. The rate of return on AEP Career Shares is equivalent to the total return on AEP stock with dividends reinvested. Participants may not withdraw any amount credited to their account until their termination of employment with AEP. Participants may elect among the same payment options for the distribution of the value of their AEP Career Shares as described above for the Supplemental Retirement Savings Plan.

Potential Payments Upon Termination of Employment or Change in Control. The Company has entered into agreements and maintains plans that will require the Company to provide compensation to the named executive officers in the event of a termination of their employment or a change in control of the Company. Actual payments will depend on the circumstances and timing of any termination of employment or change of control. In addition, in connection with any actual termination or change in control transaction, the Company may enter into agreements or establish arrangements that provide additional or alternative

benefits or amounts from those described below. The agreements and plans summarized below are complex legal documents with terms and conditions having precise meanings, which are designed to address many possible but currently hypothetical situations.

Severance. AEP currently provides full-time employees, including the named executive officers, with severance benefits under a general severance plan if their employment is terminated as the direct result of a restructuring or downsizing ("Severance-Eligible Employees") and the employee releases AEP from any and all claims. These severance benefits include:

- A lump sum severance payment equal to two weeks of base pay for each year of Company service, with a minimum of 8 weeks for employees with at least one year of AEP service;
- Continued eligibility for medical and dental benefits at the active employee rates for 18 months or until the participant becomes eligible for coverage from another employer, whichever occurs first;
- For employees who are at least age 50 with 10 years of AEP service and who do not qualify for AEP's retiree medical benefits or who will be bridged to such retiree benefit eligibility (described below), AEP also provides medical and dental benefit eligibility at rates equivalent to those provided to retirees until age 65 or until the

participant becomes eligible for coverage from another employer, whichever occurs first; and

- Outplacement services, the incremental cost of which may be up to $28,000 for executive officers.

Severance-Eligible Employees who have enough weeks of severance (up to one year) and vacation to cover a period that would allow them to become eligible for retiree medical benefits, which is available to those employees who are at least age 55 with at least 10 years of service ("Retirement-Eligible Employees") are retained as employees on a paid leave of absence until they become retirement eligible. This benefit applies in lieu of severance and unused vacation payments that these employees would otherwise receive. The Company pays any remaining severance and vacation pay at the time of their retirement. This delay of an employee's termination date does not apply to the plans providing nonqualified deferred compensation, which define a participant's termination date by reference to Internal Revenue Code Section 409A.

A Severance-Eligible executive's termination entitles that executive to a pro-rata portion of any outstanding unvested performance units that the executive has held for at least six months and to the payment of a pro-rata portion of any RSUs to the extent not already vested and paid. The pro-rated performance units will not become payable until the end of the performance period and remain subject to all performance objectives.

Severance-Eligible executives may continue financial counseling and tax preparation services for one year following their termination up to a maximum annual incremental cost to the Company for 2017 of $20,000 plus related incidental expenses of the advisor.

In addition, Ms. Hillebrand has an agreement that entitles her to a payment of one times her annual salary plus her target annual incentive opportunity if she terminates her employment because her duties are changed without her consent, provided that her termination is not a Qualifying Termination (as defined in the Company's long-term incentive awards). See Change in Control below. Payment is conditioned upon her releasing AEP from all claims, including claims for any other severance benefits.

The Company also has an Executive Severance Plan (Executive Severance Plan) that provides severance benefits to selected officers of the Company, including the named executive officers, subject to the executive's agreement to comply with the provisions of the plan, including confidentiality, non-solicitation, cooperation and non-disparagement provisions during their employment and following termination. Executives remain eligible for benefits under the general severance plan described above; however, any benefits provided under

the Executive Severance Plan will be reduced by any amounts provided under the general severance plan. Benefits under the Executive Severance Plan would be triggered by a resignation for "good reason" or an involuntary termination by the Company without "cause" (each as defined below).

The term "cause" with respect to the Executive Severance Plan means:

(i) Failure or refusal to perform a substantial part of the executive's assigned duties and responsibilities following notice and a reasonable opportunity to cure (if such failure is capable of cure);

(ii) Commission of an act of willful misconduct, fraud, embezzlement or dishonesty either in connection with the executive's duties to the Company or which otherwise is injurious to the best interest or reputation of the Company;

(iii) Repeated failure to follow specific lawful directions of the Board or any officer to whom the executive reports;

(iv) A violation of any of the material terms and conditions of any written agreement or agreements the executive may from time to time have with the Company;

(v) A material violation of any of the rules of conduct of behavior of the Company;

(vi) Conviction of, or plea of guilty or nolo contendere to, (A) a felony, (B) a misdemeanor involving an act of moral turpitude, or (C) a misdemeanor committed in connection with the executive's employment with the Company which is injurious to the best interest or reputation of the Company; or

(vii) Violation of any applicable confidentiality, non-solicitation, or non-disparagement covenants or obligations relating to the Company (including the provisions to which the executive agreed when enrolling in the plan).

An executive's termination of employment that is covered by his or her change in control agreement (described in the next section) or due to mandatory retirement, disability or death would not be considered an involuntary termination that may trigger the payment of benefits under the Executive Severance Plan.

An executive would have "good reason" for resignation under the Executive Severance Plan if there is any reduction in the executive's then current annual base salary without the executive's consent; provided, however, that a uniform percentage reduction of 10% or less in the annual base salary of all executives participating in the Executive Severance Plan who are similarly situated would not be considered good reason for resignation. Also, the Company must be given 10 days following receipt of written notice from the executive to restore the executive's base salary before his or resignation may trigger plan benefits.

If benefits under the Executive Severance Plan are triggered, the affected named executive officers would receive two times their base salary and target annual incentive payable over two years. In addition, a pro-rated portion of their outstanding unvested performance units and RSUs would vest. The pro-rated performance units will not become payable until the end of the performance period and remain subject to all performance objectives. Any severance benefits payable under the Executive Severance Plan and prorated vesting of RSUs are conditioned on the execution of an agreement by the executive officer releasing claims against the Company and committing to a non-competition obligation.

Change In Control. AEP defines "change in control" under its change in control agreements and Long-Term Incentive Plan as:

- The acquisition by any person of the beneficial ownership of securities representing more than one-third of AEP's voting stock;

- A merger or consolidation of AEP with another corporation unless AEP's voting securities outstanding immediately before such merger or consolidation continue to represent at least two-thirds of the total voting power of the surviving entity outstanding immediately after such merger or consolidation; or

- Approval by the shareholders of the liquidation of AEP or the disposition of all or substantially all of the assets of AEP.

AEP has a change in control agreement with each of the named executive officers that is triggered if there is a Qualifying Termination of the named executive officer's employment. A "Qualifying Termination" for this purpose generally occurs when the executive's employment is terminated in connection with that change in control (i) by AEP without "cause" or (ii) by the named executive officer for "good reason", each as defined below. Such termination must be no later than two years after the change in control. These agreements provide for:

- A lump sum payment equal to 2.99 times the named executive officer's annual base salary plus target annual incentive compensation award under the annual incentive program as in effect at the time of termination; and

- Outplacement services.

The term "cause" with respect to AEP's change in control agreements means:

(i) The willful and continued failure of the executive to perform the executive's duties after a written demand for performance is delivered to the executive by the Board; or

(ii) The willful conduct or omission by the executive, which the Board determines to be illegal; gross misconduct that is injurious to the Company; or a breach of the executive's fiduciary duty to the Company.

The term "good reason" with respect to AEP's change in control agreements means:

(i) An adverse change in the executive's status, duties or responsibilities from that in effect immediately prior to the change in control;

(ii) The Company's failure to pay in a timely fashion the salary or benefits to which the executive is entitled under any employment agreement in effect on the date of the change in control;

(iii) The reduction of the executive's salary as in effect on the date of the change in control;

(iv) Any action taken by the Company that would substantially diminish the aggregate projected value of the executive's awards or benefits under the Company's benefit plans or policies;

(v) A failure by the Company to obtain from any successor the assent to the change in control agreement; or

(vi) The relocation, without the executive's prior approval, of the office at which the executive is to perform services to a location that is more than fifty (50) miles from its location immediately prior to the change in control.

The Company must be given notice and an opportunity to cure any of these circumstances before they would be considered to be "good reason."

All awards under the Long-Term Incentive Plan will vest upon a "Qualifying Termination", which may occur coincident with or within one year after a change in control. The term "Qualifying Termination" with respect to long-term incentive awards generally is the same as that described for the change in control agreements, except that an executive's mandatory retirement at age 65 is explicitly excluded, and "Cause" is defined more broadly to encompass:

(i) Failure or refusal to perform assigned duties and responsibilities in a competent or satisfactory manner;

(ii) Commission of an act of dishonesty, including, but not limited to, misappropriation of funds or any property of AEP;

(iii) Engagement in activities or conduct injurious to the best interest or reputation of AEP;

(iv) Insubordination;

(v) Violation of any material term or condition of any written agreement with AEP;

(vi) Violation of any of AEP's rules of conduct of behavior;

(vii) Commission of a felony, a misdemeanor involving an act of moral turpitude, or a misdemeanor committed in connection with employment at AEP which is injurious to the best interest or reputation of AEP; or

(viii) Disclosure, dissemination, or misappropriation of confidential, proprietary, and/or trade secret information.

In addition, performance units would be deemed to have been fully earned at 100 percent of the target score upon a "Qualifying Termination" following a change in control. The value of each vested performance unit following a "Qualifying Termination" would be (1) the closing price of a share of AEP common stock on the date of the Qualifying Termination or (2) if the date of the Qualifying Termination is coincident with the change in control and if the change in control is the result of a tender offer, merger, or sale of all or substantially all of the assets of AEP, the price paid per share of common stock in that transaction.

The AEP Supplemental Benefit Plan also provides that all accrued supplemental retirement benefits to the extent then unvested become fully vested upon a change in control.

Termination Scenarios

The following tables show the incremental compensation and benefits that would have been paid to each named executive officer who was employed by AEP on December 31, 2017 assuming the hypothetical circumstances cited in each column occurred on December 31, 2017 and calculated in accordance with the methodology required by the SEC. In connection with any actual termination or change in control, the Company may enter into agreements or establish arrangements that provide additional benefits or amounts, or may alter the terms of benefits described below.

With respect to annual incentive compensation for the completed year, the initial calculated annual incentive opportunity is shown, before any individual discretionary adjustment, which varies from the actual value paid and reported in the Summary Compensation Table.

The values shown in the change in control column are triggered only if the named executive officer's employment is terminated under the circumstances (described above under Change In Control) that trigger the payment or provision of each of the types of compensation and benefits shown.

No information is provided for terminations due to disability because it is not generally AEP's practice to terminate the employment of any employee so long as they remain eligible for AEP's long-term disability benefits. AEP successively provides sick pay and then long-term disability benefits for up to two years to employees with a disability that prevents them from returning to their job. Such disability benefits continue for employees that cannot perform any occupation for which they are reasonably qualified generally until the employee reaches age 65. Because disabled participants remain employed by the Company, they continue to vest in long-term incentive awards while they are disabled. AEP treats a participant's disability as a termination to the extent required by the regulations issued under Internal Revenue Code Section 409A, but such terminations only trigger the payment of benefits that had previously vested. Employment may be terminated due to disability under a separate definition of employment termination that applies to restricted stock unit awards and compensation and benefit programs that may be considered non-qualified deferred compensation under Section 409A of the Internal Revenue Code. However restricted stock unit awards allow participants terminated due to disability to continue to vest as if their employment had continued so long as they remain continuously disabled.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2017
For Nicholas K. Akins

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change In Control	Death
Compensation:					
Base Salary ($1,375,000)	$ 0	$ 2,750,000	$0	$ 4,111,250	$ 0
Annual Incentive for Completed Year(1)	$ 1,641,970	$ 1,641,970	$0	$ 1,641,970	$ 1,641,970
Other Payment for Annual Incentives(2)	$ 0	$ 3,575,000	$0	$ 5,344,625	$ 0
Long-Term Incentives:(3)					
2016-2018 Performance Units(4)	$ 4,218,111	$ 4,218,111	$0	$ 6,327,167	$ 4,218,111
2017-2019 Performance Units(4)	$ 2,204,206	$ 2,204,206	$0	$ 6,612,619	$ 2,204,206
2015 Restricted Stock Units	$ 0	$ 631,641	$0	$ 928,968	$ 928,968
2016 Restricted Stock Units	$ 0	$ 558,652	$0	$ 1,406,070	$ 1,406,070
2017 Restricted Stock Units	$ 0	$ 661,247	$0	$ 2,204,157	$ 2,204,157
Benefits:					
Financial Counseling	$ 20,000	$ 20,000	$0	$ 20,000	$ 20,000
Outplacement Services(5)	$ 0	$ 17,000	$0	$ 17,000	$ 0
Total Incremental Compensation and Benefits	$ 8,084,287	$ 16,277,827	$0	$ 28,613,826	$ 12,623,482

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2017
For Brian X. Tierney

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change In Control	Death
Compensation:					
Base Salary ($750,000)	$ 0	$ 1,500,000	$0	$ 2,242,500	$ 0
Annual Incentive for Completed Year(1)	$ 551,377	$ 551,377	$0	$ 551,377	$ 551,377
Other Payment for Annual Incentives(2)	$ 0	$ 1,200,000	$0	$ 1,794,000	$ 0
Long-Term Incentives:(3)					
2016-2018 Performance Units(4)	$ 0	$ 1,189,480	$0	$ 1,784,220	$ 1,189,480
2017-2019 Performance Units(4)	$ 0	$ 587,775	$0	$ 1,763,326	$ 587,775
2015 Restricted Stock Units	$ 0	$ 179,269	$0	$ 263,748	$ 263,748
2016 Restricted Stock Units	$ 0	$ 157,538	$0	$ 396,542	$ 396,542
2017 Restricted Stock Units	$ 0	$ 176,325	$0	$ 587,751	$ 587,751
Benefits:					
Financial Counseling	$ 0	$ 20,000	$0	$ 20,000	$ 20,000
Outplacement Services(5)	$ 0	$ 17,000	$0	$ 17,000	$ 0
Total Incremental Compensation and Benefits	$ 551,377	$ 5,578,764	$0	$ 9,420,464	$ 3,596,673

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2017
For David M. Feinberg

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change In Control	Death
Compensation:					
Base Salary ($632,000)	$ 0	$ 1,264,000	$0	$ 1,889,680	$ 0
Annual Incentive for Completed Year(1)	$ 406,537	$ 406,537	$0	$ 406,537	$ 406,537
Other Payment for Annual Incentives(2)	$ 0	$ 884,800	$0	$ 1,322,776	$ 0
Long-Term Incentives:(3)					
2016-2018 Performance Units(4)	$ 0	$ 707,351	$0	$ 1,061,027	$ 707,351
2017-2019 Performance Units(4)	$ 0	$ 352,695	$0	$ 1,058,084	$ 352,695
2015 Restricted Stock Units	$ 0	$ 93,852	$0	$ 138,091	$ 138,091
2016 Restricted Stock Units	$ 0	$ 93,678	$0	$ 235,792	$ 235,792
2017 Restricted Stock Units	$ 0	$ 105,786	$0	$ 352,621	$ 352,621
Benefits:					
Financial Counseling	$ 0	$ 20,000	$0	$ 20,000	$ 20,000
Outplacement Services(5)	$ 0	$ 17,000	$0	$ 17,000	$ 0
Total Incremental Compensation and Benefits	$ 406,537	$ 3,945,699	$0	$ 6,501,608	$ 2,213,087

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2017
For Lisa M. Barton

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($550,000)	$ 0	$ 1,100,000	$0	$ 1,644,500	$ 0
Annual Incentive for Completed Year(1)	$ 353,705	$ 353,705	$0	$ 353,705	$ 353,705
Other Payment for Annual Incentives(2)	$ 0	$ 770,000	$0	$ 1,151,150	$ 0
Long-Term Incentives:(3)					
2016-2018 Performance Units(4)	$ 0	$ 629,612	$0	$ 944,418	$ 629,612
2017-2019 Performance Units(4)	$ 0	$ 352,695	$0	$ 1,058,084	$ 352,695
2015 Restricted Stock Units	$ 0	$ 93,852	$0	$ 138,091	$ 138,091
2016 Restricted Stock Units	$ 0	$ 83,366	$0	$ 209,895	$ 209,895
2017 Restricted Stock Units	$ 0	$ 105,786	$0	$ 352,621	$ 352,621
Benefits:					
Financial Counseling	$ 0	$ 20,000	$0	$ 20,000	$ 20,000
Outplacement Services(5)	$ 0	$ 17,000	$0	$ 17,000	$ 0
Total Incremental Compensation and Benefits	$ 353,705	$ 3,526,016	$0	$ 5,889,464	$ 2,056,619

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2017
For Lana L. Hillebrand

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($577,000)	$ 0	$ 1,154,000	$0	$ 1,725,230	$ 0
Annual Incentive for Completed Year(1)	$ 371,167	$ 371,167	$0	$ 371,167	$ 371,167
Other Payment for Annual Incentives(2)	$ 0	$ 807,800	$0	$ 1,207,661	$ 0
Long-Term Incentives:(3)					
2016-2018 Performance Units(4)	$ 566,587	$ 566,587	$0	$ 849,881	$ 566,587
2017-2019 Performance Units(4)	$ 279,198	$ 279,198	$0	$ 837,594	$ 279,198
2015 Restricted Stock Units	$ 0	$ 84,817	$0	$ 124,848	$ 124,848
2016 Restricted Stock Units	$ 0	$ 75,037	$0	$ 188,928	$ 188,928
2017 Restricted Stock Units	$ 0	$ 83,737	$0	$ 279,125	$ 279,125
Benefits:					
Financial Counseling	$ 20,000	$ 20,000	$0	$ 20,000	$ 20,000
Outplacement Services(5)	$ 0	$ 17,000	$0	$ 17,000	$ 0
Total Incremental Compensation and Benefits	$1,236,952	$ 3,459,343	$0	$ 5,621,434	$ 1,829,853

(1) Executive officers and all other employees are eligible for an annual incentive award based on their earnings for the year if they remain employed with AEP through year-end, if they die or if they incur a retirement-eligible termination. The amount shown is the calculated annual incentive opportunity, as shown in the table in Compensation Discussion and Analysis, but annual incentives for executive officers are awarded at the discretion of the HR Committee or independent members of the Board pursuant to the award determination process described in the Compensation Discussion and Analysis.

(2) The amount shown in the Severance column is two times the target annual incentive opportunity for each of the named executive officers. The amount shown in the Change-In-Control column is 2.99 times the target annual incentive opportunity for each of the named executive officers.

(3) The long-term incentive values shown represent the values that would be paid under such circumstances shown in each column based on the closing price of AEP common stock on December 31, 2017, which is the methodology required by the SEC. These amounts differ from the values calculated in accordance with FASB ASC Topic 718. These amounts also differ from the amounts that would actually be paid under such circumstances, for awards granted prior to 2017, which are paid in cash. The amounts for awards granted prior to 2017 would be based on the 20-day average closing market price of AEP common stock as of the end of the 2016-2018 performance period and as of the termination date for the 2015 and 2016 Restricted Stock Units. The 2017 Restricted Stock Units and the 2017-2019 performance units are paid in shares, except that the 2017-2019 performance units would be paid in cash in the event of the executive's termination of employment in connection with a change in control.

(4) The target value of performance unit awards are shown. The actual value paid in the event of resignation or retirement, severance or death, if any, will depend on the actual performance score for the full performance period. Any payments for awards under those circumstances are not paid until the end of the three year performance period. In the event of a qualifying termination in connection with a change in control, awards would be paid at a target performance score as soon as administratively practical after the change in control.

(5) Represents the maximum cost of the Company-paid outplacement services, which the Company provides through an unaffiliated third party vendor.

The following table shows the value of previously earned and vested compensation and benefits as of December 31, 2017, that would have been provided to each named executive officer following a termination of his or her employment on December 31, 2017. These amounts were generally earned or vested over multiple years of service to the Company.

Non-Incremental Post-Termination Compensation and Benefits on December 31, 2017

	Long-Term Incentives		Benefits		
Name	Vested Performance Units (1)	AEP Career Shares (2)	Vacation Payout (3)	Post Retirement Benefits (4)	Deferred Compensation (5)
Nicholas K. Akins	$10,716,868	$8,076,040	$39,663	$2,239,040	$2,254,667
Brian X. Tierney	$ 3,041,605	$1,442,494	$ 4,327	$1,362,211	$3,792,456
David M. Feinberg	$ 1,592,202	$2,407,738	$46,033	$ 369,905	$ 595,507
Lisa M. Barton	$ 1,592,202	$1,825,340	$12,163	$ 449,014	$ 579,470
Lana L. Hillebrand	$ 1,439,176	$2,012,484	$27,186	$ 718,820	$ 483,255

(1) Represents the value of performance units that vested on December 31, 2017 calculated using the market value of these shares on

December 31, 2017. However, the actual value realized from these performance units would be based on the 20-day average closing market price of AEP common stock on the vesting date.

(2) Represents the value of AEP share equivalents deferred mandatorily into the AEP Stock Ownership Requirement Plan calculated using the market value of these shares on December 31, 2017.

(3) Represents accumulated but unused vacation.

(4) Represents the lump sum benefit calculated for the named executive officer pursuant to the terms of the AEP Retirement Plan, the AEP Supplemental Benefit Plan and the CSW Executive Retirement Plan, as applicable.

(5) Includes balances from the Supplemental Retirement Savings Plan and the Incentive Compensation Deferral Plans, but does not include AEP Career Share balances, which are listed separately in column (2).

TRANSACTIONS WITH RELATED PERSONS

The American Electric Power Company, Inc. Related Person Transaction Approval Policy (Policy) was adopted by the Board in December 2006. The written Policy is administered by the Corporate Governance Committee. A copy of the Policy is available on our website at www.aep.com/investors/corporateleadersandgovernance.

The Policy defines a “Transaction with a Related Person” as any transaction or series of transactions in which (i) the Company or a subsidiary is a participant, (ii) the aggregate amount involved exceeds $120,000 and (iii) any “Related Person” has a direct or indirect material interest. A “Related Person” is any director or executive officer of the Company, any nominee for director, any shareholder owning in excess of five percent of the total equity of the Company and any immediate family member of any such person.

The Corporate Governance Committee considers all of the relevant facts and circumstances in determining whether or not to approve a Transaction with a Related Person and approves only those transactions that it believes are in the best interests of the Company and its shareholders.

The Corporate Governance Committee considers various factors, including, among other things: the nature of the Related Person’s interest in the transaction; whether the transaction involves arm’s-length bids or market prices and terms; the materiality of the transaction to each party; the availability of the product or services through other sources; whether the transaction would impair the judgment of a director or executive officer to act in the best interest of the Company; the acceptability of the transaction to the Company’s regulators; and in the case of a non-employee director, whether the transaction would impair his or her independence or status as an “outside” or “non-employee” director.

If Company management determines it is impractical or undesirable to wait until a meeting of the Corporate Governance Committee to consummate a Transaction with a Related Person, the Chair of the Corporate Governance Committee may review and approve the Transaction with a Related Person. Any such approval is reported to the Corporate Governance Committee at or before its next regularly scheduled meeting.

No approval or ratification of a Transaction with a Related Person supersedes the requirements of the Company’s Code of Business Conduct and Ethics for Members of the Board of Directors or AEP’s Principles of Business Conduct applicable to any executive officer. To the extent applicable, any Transaction with a Related Person is also considered in light of the requirements set forth in those documents.

Since January 1, 2017, there have been no transactions, and there are no currently proposed transactions, involving an amount exceeding $120,000 in which AEP was or is expected to be a participant and in which any Related Person had a direct or indirect material interest.

None of the managers of the Company are independent.

Pay Ratio Disclosure

Following is a reasonable estimate, prepared under applicable SEC rules, of the ratio of the annual total compensation of our Chief Executive Officer to the median of the annual total compensation of all of our employees (except for the CEO). We identified the median employee by first determining the 2017 total wages for each employee (except for our CEO), who were employed by us on October 31, 2017. Based on this compensation measure, we then identified the median employee from among our entire employee population. After identifying the median employee, we calculated annual total compensation for such employee using the same methodology we use for our named executive officers as set forth in the 2017 Summary Compensation Table in this proxy statement.

Mr. Akins, who was both Chairman and CEO had 2017 annual total compensation of $11,530,461, as reflected in the Summary Compensation Table included in this Proxy Statement. The 2017 annual total compensation of our median employee (other than the CEO) was $113,084. The median employee's total compensation includes base wages,

overtime earnings, annual incentive compensation, the change in the present value of the employee's pension benefits and the Company's matching contributions to the retirement savings plan. Based on the foregoing, our estimate of the 2017 ratio of the annual total compensation of our CEO to the median annual total compensation of all our employees (other than the CEO) was 102 to 1.

Because the SEC rules for identifying the median of the annual total compensation of our employees and calculating the pay ratio based on that employee's annual total compensation allow companies to adopt a variety of methodologies, and to make reasonable estimates and assumptions that reflect their employee populations and compensation practices, the pay ratio reported by other companies may not be comparable to the pay ratio for our Company, as other companies have different employee populations and compensation practices and may utilize different methodologies, estimates and assumptions in calculating their pay ratios.

THE EXCHANGE OFFERS

Purpose and Effect of the Exchange Offers

The Outstanding Notes were issued on September 28, 2017 and sold to the initial purchasers pursuant to a purchase agreement in transactions not requiring registration under the Securities Act. The initial purchasers subsequently sold the Outstanding Notes to qualified institutional buyers (as defined in Rule 144A under the Securities Act) in reliance on Rule 144A, and to persons in offshore transactions in reliance on Regulation S under the Securities Act.

We entered into a registration rights agreement with representatives of the initial purchasers of the Outstanding Notes in which we agreed, under certain circumstances, to file a registration statement relating to offers to exchange the Outstanding Notes for Exchange Notes and to use commercially reasonable efforts to cause such registration statement to be declared effective under the Securities Act no later than 270 days after the original issue date of the Outstanding Notes and to pay additional interest as described below if we do not consummate the Exchange Offers within 315 days after the issue date of the Outstanding Notes. The Exchange Notes will have terms identical in all material respects to the Outstanding Notes of the related series, except that the Exchange Notes will not contain certain terms with respect to transfer restrictions, registration rights and additional interest for failure to observe certain obligations in the registration rights agreement.

Under the circumstances set forth below, we will use commercially reasonable efforts to cause the SEC to declare effective a shelf registration statement with respect to the resale of the Outstanding Notes within the time periods specified in the registration rights agreement and keep the statement effective for one year from the original issue date of the Outstanding Notes, or such shorter period as described in the registration rights agreement. These circumstances include:

- if a change in law or in applicable interpretations of the staff of the SEC does not permit us to effect a registered exchange offer;

- if a registered exchange offer is not consummated within 315 days after the date of issuance of the Outstanding Notes;

- if any initial purchaser of the Outstanding Notes so requests with respect to Notes not eligible to be exchanged for Exchange Notes in the Exchange Offer and held by it following consummation of the Exchange Offer; or

- if any holder (other than a holder that is a broker-dealer electing to exchange Outstanding Notes acquired for its own account as a result of market making activities or other trading activities) notifies us during the 20 business days following consummation of an Exchange Offer that it was not eligible to participate in such Exchange Offer or any holder (other than a holder that is a broker-dealer electing to exchange Outstanding Notes acquired for its own account as a result of market making activities or other trading activities) who participates in an Exchange Offer does not receive freely tradeable Exchange Notes in such Exchange Offer.

Except for certain circumstances specified in the registration rights agreement, we will pay additional interest if:

- neither a registration statement relating to offers to exchange the Outstanding Notes for Exchange Notes nor a shelf registration statement with respect to the resale of the Outstanding Notes (if required) is filed by us within the applicable time periods specified above;

- neither the Exchange Offer registration statement nor a shelf registration statement (if required) is declared effective by the SEC within the applicable time periods specified above;

- the applicable Exchange Offer is not consummated within 315 days after the initial issuance of the Outstanding Notes (or if the 315th day is not a business day, by the first business day thereafter); or

- after the Exchange Offer registration statement or the shelf registration statement, as the case may be, is declared effective, such Exchange Offer registration statement or shelf registration statement thereafter ceases to be effective or usable (subject to certain exceptions) in connection with resales of Exchange Notes or Outstanding Notes, as the case may be, as provided in and during the periods specified in the registration rights agreement.

We sometimes refer to an event referred to in the first through fourth bullet items above as a Registration Default.

Additional interest, if payable, will be payable on the Outstanding Notes at a rate of 0.25% per annum for the first 90 days from and including the date on which any Registration Default occurs, and such additional interest rate shall increase by an additional 0.25% per annum thereafter; provided, however, that the additional interest rate on the Outstanding Notes will not at any time exceed 0.50% per annum. Additional interest will cease to accrue on and after the date on which all Registration Defaults have been cured. Any such additional interest payable will be payable on interest payment dates in addition to interest payable from time to time on the Outstanding Notes and Exchange Notes.

If you wish to exchange your Outstanding Notes for Exchange Notes in any of the Exchange Offers, you will be required to make the following written representations:

- you are not our affiliate within the meaning of Rule 405 of the Securities Act;

- you have no arrangement or understanding with any person to participate in a distribution (within the meaning of the Securities Act) of the Exchange Notes in violation of the provisions of the Securities Act;

- you are not engaged in, and do not intend to engage in, a distribution of the Exchange Notes; and you are acquiring the Exchange Notes in the ordinary course of your business.

Each broker-dealer that receives Exchange Notes for its own account in exchange for Outstanding Notes, where the broker-dealer acquired the Outstanding Notes as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Notes and that it did not purchase its Outstanding Notes from us or any of our affiliates. See "Plan of Distribution."

Resale of Exchange Notes

We have not requested, and do not intend to request, an interpretation by the staff of the SEC as to whether the Exchange Notes issued pursuant to the Exchange Offers in exchange for the Outstanding Notes may be offered for sale, resold or otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act. Instead, based on interpretations by the SEC set forth in no-action letters issued to third parties, we believe that you may resell or otherwise transfer Exchange Notes issued in the Exchange Offers without complying with the registration and prospectus delivery provisions of the Securities Act if:

- you are acquiring the Exchange Notes in the ordinary course of your business;
- you have no arrangements or understanding with any person to participate in the distribution of the Exchange Notes within the meaning of the Securities Act;
- you are not our "affiliate," as defined in Rule 405 of the Securities Act; and
- you are not engaged in, and do not intend to engage in, a distribution of the Exchange Notes.

If you are our affiliate, or are engaging in, or intend to engage in, or have any arrangement or understanding with any person to participate in, a distribution of the Exchange Notes, or are not acquiring the Exchange Notes in the ordinary course of your business:

- you cannot rely on the position of the SEC set forth in *Morgan Stanley & Co. Incorporated* (available June 5, 1991) and *Exxon Capital Holdings Corporation* (available May 13, 1988), as interpreted in the SEC's letter to Shearman & Sterling, (available July 2, 1993), or similar no-action letters; and
- in the absence of an exception from the position stated immediately above, you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the Exchange Notes.

This prospectus may be used for an offer to resell or transfer the Exchange Notes only as specifically set forth in this prospectus. With regard to broker-dealers, only broker-dealers that acquired the Outstanding Notes as a result of market-making activities or other trading activities may participate in the Exchange Offers. Each broker-dealer that receives Exchange Notes for its own account in exchange for Outstanding Notes, where such Outstanding Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of the Exchange Notes. Read "Plan of Distribution" for more details regarding the transfer of Exchange Notes.

Our belief that the Exchange Notes may be offered for resale without compliance with the registration or prospectus delivery provisions of the Securities Act is based on interpretations of the SEC for other exchange offers that the SEC expressed in some of its no-action letters to other issuers in exchange offers like ours. We have not sought a no-action letter in connection with the Exchange Offers, and we cannot guarantee that the SEC would make a similar decision about our Exchange Offers. If our belief is wrong, or if you cannot truthfully make the representations mentioned above, and you transfer any Exchange Note issued to you in the Exchange Offers without meeting the registration and prospectus delivery requirements of the Securities Act, or without an exemption from such requirements, you could incur liability under the Securities Act. We are not indemnifying you for any such liability.

Terms of the Exchange Offers

On the terms and subject to the conditions set forth in this prospectus and in the accompanying letters of transmittal, we will accept for exchange in the Exchange Offers any Outstanding Notes that are validly tendered and not validly withdrawn prior to the Expiration Date. Outstanding Notes may only be tendered in minimum denominations of $2,000 and integral multiples of $1,000 in excess of $2,000, and any untendered Outstanding Notes must also be in a minimum denomination of $2,000. We will issue Exchange Notes in principal amount identical to Outstanding Notes surrendered in the Exchange Offers.

The form and terms of the Exchange Notes will be identical in all material respects to the form and terms of the Outstanding Notes of the related series except the Exchange Notes will be registered under the Securities Act, will not bear legends restricting their transfer and will not provide for any payment of additional interest upon our failure to fulfill our obligations under the registration rights agreement to complete the Exchange Offers, or file, and cause to be effective, a shelf registration statement, if required thereby, within the specified time period. The Exchange Notes will evidence the same debt as the Outstanding Notes of the related series. The Exchange Notes will be issued under and entitled to the benefits of the Indenture. For a description of the Indenture, see "Description of the Exchange Notes."

No interest will be paid in connection with the exchange. The Exchange Notes will bear interest from the last Interest Payment Date (as defined under "Description of the Exchange Notes-Maturity; Interest") on the Outstanding Notes surrendered in the Exchange Offers. Accordingly, the holders of Outstanding Notes that are accepted for exchange will not receive accrued but unpaid interest on Outstanding Notes at the time of tender. Rather, that interest will be payable on the Exchange Notes delivered in exchange for the Outstanding Notes on the first Interest Payment Date after the Expiration Date (as defined below under "-Expiration Date, Extensions and Amendments").

The Exchange Offers are not conditioned upon any minimum aggregate principal amount of Outstanding Notes being tendered for exchange.

As of the date of this prospectus, $125,030,000 aggregate principal amount of our 3.10% Senior Notes, Series D due 2026 and $500,000,000 aggregate principal amount of our 3.75% Senior Notes, Series H due 2047 are outstanding. This prospectus and the letters of transmittal are being sent to all registered holders of Outstanding Notes. There will be no fixed record date for determining registered holders of Outstanding Notes entitled to participate in the Exchange Offers. We intend to conduct the Exchange Offers in accordance with the provisions of the registration rights agreement, the applicable requirements of the Securities Act and the Exchange Act, and the rules and regulations of the SEC. Outstanding Notes that are not tendered for exchange in the Exchange Offers will remain outstanding and continue to accrue interest and will be entitled to the rights and benefits such holders have under the Indenture relating to such holders' series of Outstanding Notes except we will not have any further obligation to you to provide for the registration of the Outstanding Notes under the registration rights agreement.

We will be deemed to have accepted for exchange properly tendered Outstanding Notes when we have given written notice of the acceptance to the Exchange Agent. The Exchange Agent will act as agent for the tendering holders for the purposes of receiving the Exchange Notes from us and delivering Exchange Notes to holders. Subject to the terms of the registration rights agreement, we expressly reserve the right to amend or terminate the Exchange Offers and to refuse to accept Exchange Notes upon the occurrence of any of the conditions specified below under "-Conditions to the Exchange Offers."

If you tender your Outstanding Notes in the Exchange Offers, you will not be required to pay brokerage commissions or fees or, subject to the instructions in the letter of transmittal, transfer taxes with respect to the exchange of Outstanding Notes. We will pay all charges and expenses, other than certain applicable taxes described below in connection with the Exchange Offers. It is important that you read "-Fees and Expenses" below for more details regarding fees and expenses incurred in the Exchange Offers.

If you are a broker-dealer and receive Exchange Notes for your own account in exchange for Outstanding Notes that you acquired as a result of market-making activities or other trading activities, you must acknowledge that you will deliver this prospectus in connection with any resale of the Exchange Notes and that you did not purchase your Outstanding Notes from us or any of our affiliates. Read "Plan of Distribution" for more details regarding the transfer of Exchange Notes.

We make no recommendation to you as to whether you should tender or refrain from tendering all or any portion of your Outstanding Notes into these Exchange Offers. In addition, no one has been authorized to make this recommendation. You must make your own decision whether to tender into these Exchange Offers and, if so, the aggregate amount of Outstanding Notes to tender after reading this prospectus and the letter of transmittal and consulting with your advisors, if any, based on your financial position and requirements.

Expiration Date, Extensions and Amendments

The Exchange Offers expire at 5:00 p.m., New York City time, on May 7, 2018, which we refer to as the "Expiration Date." However, if we, in our sole discretion, extend the period of time for which the Exchange Offers are open, the term "Expiration Date" will mean the latest time and date to which we shall have extended the expiration of the Exchange Offers.

To extend the period of time during which the Exchange Offers are open, we will notify the Exchange Agent of any extension by written notice, followed by notification by press release or other public announcement to the registered holders of the Outstanding Notes no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled Expiration Date. During any extension, all Outstanding Notes previously tendered and not accepted for exchange will remain subject to the applicable Exchange Offer unless validly withdrawn.

We also reserve the right, in our sole discretion:

- to delay accepting for exchange any Outstanding Notes (only in the case that we amend or extend the Exchange Offers);
- to extend the Expiration Date and retain all Outstanding Notes tendered in the Exchange Offers, subject to your right to withdraw your tendered Outstanding Notes as described under "-Withdrawal Rights";
- to terminate any of the Exchange Offers if we determine that any of the conditions set forth below under "-Conditions to the Exchange Offers" have not been satisfied; and
- subject to the terms of the registration rights agreement, to amend the terms of any of the Exchange Offers in any manner or waive any condition to the Exchange Offers.

Any delay in acceptance, extension, termination or amendment will be followed as promptly as practicable by written notice to the registered holders of the Outstanding Notes. If we amend any of the Exchange Offers in a manner that we determine to constitute a material change, we will promptly disclose the amendment by press release or other public announcement as required by Rule 14e-1(d) of the Exchange Act, and we will extend such Exchange Offer to the extent required by law.

In the event we terminate the Exchange Offers, all Outstanding Notes previously tendered will be returned promptly to the tendering holders.

Conditions to the Exchange Offers

Despite any other term of the Exchange Offers, we will not be required to accept for exchange, or to issue Exchange Notes in exchange for, any Outstanding Notes and we may terminate or amend any of the Exchange Offers as provided in this prospectus prior to the Expiration Date if in our reasonable judgment:

- the Exchange Offers or the making of any exchange by a holder violates any applicable law or interpretation of the SEC; or

- any action or proceeding has been instituted or threatened in writing in any court or by or before any governmental agency with respect to the Exchange Offers that, in our judgment, would reasonably be expected to impair our ability to proceed with the Exchange Offers.

In addition, we will not be obligated to accept for exchange the Outstanding Notes of any holder that has not made to us:

- the representations described under "-Purpose and Effect of the Exchange Offers"; or

- any other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to make available to us an appropriate form for registration of the Exchange Notes under the Securities Act.

We expressly reserve the right at any time or at various times to extend the period of time during which the Exchange Offers are open. Consequently, we may delay acceptance of any Outstanding Notes by giving notice by press release or other public announcement as required by Rule 14e-1(d) of the Exchange Act of such extension to the holders. We will return any Outstanding Notes that we do not accept for exchange for any reason without expense to the tendering holder promptly after the expiration or termination of the Exchange Offers. We also expressly reserve the right to amend or terminate any of the Exchange Offers and to reject for exchange any Outstanding Notes not previously accepted for exchange, if we determine that any of the conditions of the Exchange Offers specified above have not been satisfied. We will give notice by press release or other public announcement as required by Rule 14e-1(d) of the Exchange Act of any extension, amendment, non-acceptance or termination to the holders of the Outstanding Notes

as promptly as practicable. If we amend an Exchange Offer in a manner that we determine to constitute a material change, including the waiver of a material condition, we will promptly disclose the amendment by press release or other public announcement as required by Rule 14e-1(d) of the Exchange Act and will extend the offer period if necessary so that at least five business days remain in the offer following notice of the material change. In the case of any extension, such notice will be issued no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled Expiration Date.

We reserve the right to waive any defects, irregularities or conditions to the exchange as to particular Outstanding Notes. These conditions are for our sole benefit, and we may assert them regardless of the circumstances that may give rise to them or waive them in whole or in part at any or at various times prior to the expiration of the Exchange Offers in our sole discretion. If we fail at any time to exercise any of the foregoing rights, this failure will not constitute a waiver of such right. Each such right will be deemed an ongoing right that we may assert at any time or at various times prior to the expiration of the Exchange Offers.

In addition, we will not accept for exchange any Outstanding Notes tendered, and will not issue Exchange Notes in exchange for any such Outstanding Notes, if at such time any stop order is threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the Indenture under the Trust Indenture Act of 1939, as amended.

Procedures for Tendering Outstanding Notes

To tender your Outstanding Notes in the Exchange Offers, you must comply with either of the following:

- complete, sign and date the letter of transmittal, or a facsimile of the letter of transmittal, have the signature(s) on the letter of transmittal guaranteed if required by the letter of transmittal and mail or deliver such letter of transmittal or facsimile thereof to the Exchange Agent at the address set forth below under "-Exchange Agent" prior to the Expiration Date; or

- comply with DTC's Automated Tender Offer Program procedures described below.

In addition:

- the Exchange Agent must receive certificates for Outstanding Notes along with the letter of transmittal prior to the expiration of the Exchange Offers;

- the Exchange Agent must receive a timely confirmation of book-entry transfer of Outstanding Notes into the Exchange Agent's account at DTC according to the procedures for book-entry transfer described below and a properly transmitted Agent's Message (defined below) prior to the expiration of the Exchange Offers; or

- you must comply with the guaranteed delivery procedures described below.

The term "*Agent's Message*" means a message transmitted by DTC, received by the Exchange Agent and forming part of the book-entry confirmation, which states that:

- DTC has received an express acknowledgment from a participant in its Automated Tender Offer Program that is tendering Outstanding Notes that are the subject of the book-entry confirmation;

- the participant has received and agrees to be bound by the terms of the letter of transmittal or, in the case of an Agent's Message relating to guaranteed delivery, that such participant has received and agrees to be bound by the notice of guaranteed delivery; and

- we may enforce that agreement against such participant. DTC is referred to herein as a "book-entry transfer facility."

Your tender, if not withdrawn prior to the expiration of the Exchange Offers, constitutes an agreement between us and you upon the terms and subject to the conditions described in this prospectus and in the letter of transmittal.

The method of delivery of Outstanding Notes, letters of transmittal and all other required documents to the Exchange Agent is at your election and risk. Delivery of such documents will be deemed made only when actually received by the Exchange Agent. We recommend that instead of delivery by mail, you use an overnight or hand delivery service, properly insured. If you determine to make delivery by mail, we suggest that you use properly insured, registered mail with return receipt requested. In all cases, you should allow sufficient time to assure timely delivery to the Exchange Agent before the expiration of the Exchange Offers. Letters of transmittal and certificates representing Outstanding Notes should be sent only to the Exchange Agent, and not to us or to DTC or any other book-entry transfer facility. No alternative, conditional or contingent tenders of Outstanding Notes will be accepted, except as described below under "—Guaranteed Delivery Procedures." You may request that your broker, dealer, commercial bank, trust company or nominee effect the above transactions for you.

If you are a beneficial owner whose Outstanding Notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your Outstanding Notes, you should promptly contact the registered holder and instruct the registered holder to tender on your behalf. If you wish to tender the Outstanding Notes yourself, you must, prior to completing and executing the letter of transmittal and delivering your Outstanding Notes, either:

- make appropriate arrangements to register ownership of the Outstanding Notes in your name; or

- obtain a properly completed bond power from the registered holder of Outstanding Notes.

The transfer of registered ownership may take considerable time and may not be able to be completed prior to the expiration of the Exchange Offers.

Signatures on the letter of transmittal or a notice of withdrawal (as described below in "-Withdrawal Rights"), as the case may be, must be guaranteed by a member firm of a registered national securities exchange or of the Financial Industry Regulatory Authority, a commercial bank or trust company having an office or correspondent in the United States or another "eligible guarantor institution" within the meaning of Rule 17A(d)-15 under the Exchange Act unless the Outstanding Notes surrendered for exchange are tendered:

- by a registered holder of the Outstanding Notes who has not completed the box entitled "Special Registration Instructions" or "Special Delivery Instructions" on the letter of transmittal; or

- for the account of an eligible guarantor institution.

If the letter of transmittal is signed by a person other than the registered holder of any Outstanding Notes listed on the Outstanding Notes, such Outstanding Notes must be endorsed or accompanied by a properly completed bond power. The bond power must be signed by the registered holder as the registered holder's name appears on the Outstanding Notes, and an eligible guarantor institution must guarantee the signature on the bond power.

If the letter of transmittal, any certificates representing Outstanding Notes or bond powers are signed by trustees, executors, administrators, guardians, attorneys-in-fact, officers of corporations or others acting in a fiduciary or representative capacity, those persons should also indicate when signing and, unless waived by us, they should also submit evidence satisfactory to us of their authority to so act.

The Exchange Agent and DTC have confirmed that any financial institution that is a participant in DTC's system may use DTC's Automated Tender Offer Program to tender Outstanding Notes. Participants in the program may, instead of physically completing and signing the letter of transmittal and delivering it to the Exchange Agent, electronically transmit their acceptance of Outstanding Notes for exchange by causing DTC to transfer the Outstanding Notes to the Exchange Agent in accordance with DTC's Automated Tender Offer Program procedures for transfer. DTC will then send an Agent's Message to the Exchange Agent.

Book-Entry Delivery Procedures

Promptly after the date of this prospectus, the Exchange Agent will establish an account with respect to the Outstanding Notes at DTC, as the book-entry transfer facility, for purposes of the Exchange Offers. Any financial institution that is a participant in the book-entry transfer facility's system may make book-entry delivery of the Outstanding Notes by causing the book-entry transfer facility to transfer those Outstanding Notes into the Exchange Agent's account at the facility in accordance with the facility's procedures for such transfer. To be timely, book-entry delivery of Outstanding Notes requires receipt of a confirmation of a book-entry transfer, or a "book-entry confirmation," prior to the Expiration Date.

In addition, in order to receive Exchange Notes for tendered Outstanding Notes, an Agent's Message in connection with a book-entry transfer into the Exchange Agent's account at the book-entry transfer facility or the letter of transmittal or a manually signed facsimile thereof, together with any required signature guarantees and any other required documents must be delivered or transmitted to and received by the Exchange Agent at its address set forth on the cover page of the letter of transmittal prior to the expiration of the Exchange Offers. Holders of Outstanding Notes who are unable to deliver confirmation of the book-entry tender of their Outstanding Notes into the Exchange Agent's account at the book-entry transfer facility or an Agent's Message or a letter of transmittal or a manually signed facsimile thereof in lieu thereof and all other documents required by the letter of transmittal to the Exchange Agent prior to the expiration of the Exchange Offers must tender their Outstanding Notes according to the guaranteed delivery procedures described below. Tender will not be deemed made until such documents are received by the Exchange Agent. Delivery of documents to the book-entry transfer facility does not constitute delivery to the Exchange Agent.

Guaranteed Delivery Procedures

If you wish to tender your Outstanding Notes but your Outstanding Notes are not immediately available or you cannot deliver your Outstanding Notes, the letter of transmittal or any other required documents to the Exchange Agent or comply with the procedures under DTC's Automatic Tender Offer Program in the case of Outstanding Notes, prior to the Expiration Date, you may still tender if:

- the tender is made through an eligible guarantor institution;
- prior to the Expiration Date, the Exchange Agent receives from such eligible guarantor institution either a properly completed and duly executed notice of guaranteed delivery, by facsimile transmission, mail, or hand delivery or a properly transmitted Agent's Message and notice of guaranteed delivery, that (1) sets forth your name and address, the certificate number(s) of such Outstanding Notes and the principal amount of Outstanding Notes tendered; (2) states that the tender is being made thereby; and (3) guarantees that, within three New York Stock Exchange trading days after the Expiration Date, the letter of transmittal, or facsimile thereof, together with the Outstanding Notes or a book-entry confirmation (including an Agent's Message), and any other documents required by the letter of transmittal, will be deposited by the eligible guarantor institution with, or transmitted by the eligible guarantor to, the Exchange Agent; and
- the Exchange Agent receives the properly completed and executed letter of transmittal or facsimile thereof, with any required signature guarantees, as well as certificate(s) representing all tendered Outstanding Notes in proper form for transfer or a book-entry confirmation of transfer of the Outstanding Notes (including an Agent's Message) into the Exchange Agent's account at DTC and all other documents required by the letter of transmittal within three New York Stock Exchange trading days after the Expiration Date.

Upon request, the Exchange Agent will send to you a notice of guaranteed delivery if you wish to tender your Outstanding Notes according to the guaranteed delivery procedures.

Acceptance of Outstanding Notes for Exchange

In all cases, we will promptly issue Exchange Notes of the applicable series for Outstanding Notes that we have accepted for exchange under the Exchange Offers only after the Exchange Agent timely receives:

- Outstanding Notes or a timely book-entry confirmation of such Outstanding Notes into the Exchange Agent's account at the book-entry transfer facility; and
- a properly completed and duly executed letter of transmittal and all other required documents or a properly transmitted Agent's Message.

In addition, each broker-dealer that is to receive Exchange Notes for its own account in exchange for Outstanding Notes must represent that such Outstanding Notes were acquired by that broker-dealer as a result of market-making activities or other trading activities and must acknowledge that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the Exchange Notes. The letters of transmittal state that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. See "Plan of Distribution."

We will interpret the terms and conditions of the Exchange Offers, including the letters of transmittal and the instructions to the letters of transmittal, and will resolve all questions as to the validity, form, eligibility, including time of receipt, and acceptance of Outstanding Notes tendered for exchange. Our determinations in this regard will be final and binding on all parties. We reserve the absolute right to reject any and all tenders of any particular Outstanding Notes not properly tendered or to not accept any particular Outstanding Notes if the acceptance might, in our or our counsel's judgment, be unlawful. We also reserve the right to waive any defects or irregularities as to any particular Outstanding Notes prior to the expiration of the Exchange Offers.

Unless waived, any defects or irregularities in connection with tenders of Outstanding Notes for exchange must be cured within such reasonable period of time as we determine. Neither the Company, the Exchange Agent nor any other person will be under any duty to give notification of any defect or irregularity with respect to any tender of Outstanding Notes for exchange, nor will any of them incur any liability for any failure to give notification. Any certificates representing Outstanding Notes received by the Exchange Agent that are not properly tendered and as to which the irregularities have not been cured or waived will be returned by the Exchange Agent to the tendering holder, unless otherwise provided in the letter of transmittal, promptly after the expiration or termination of the Exchange Offers.

Withdrawal Rights

Except as otherwise provided in this prospectus, you may withdraw your tender of Outstanding Notes at any time prior to 5:00 p.m., New York City time, on the Expiration Date.

For a withdrawal to be effective:

- the Exchange Agent must receive a written notice, which may be by facsimile or letter, of withdrawal at its address set forth below under "-Exchange Agent"; or
- you must comply with the appropriate procedures of DTC's Automated Tender Offer Program system for such withdrawal.

Any notice of withdrawal must:

- specify the name of the person who tendered the Outstanding Notes to be withdrawn;
- identify the Outstanding Notes to be withdrawn, including the certificate numbers and principal amount of the Outstanding Notes; and

- where certificates for Outstanding Notes have been transmitted, specify the name in which such Outstanding Notes were registered, if different from that of the withdrawing holder.

If certificates for Outstanding Notes have been delivered or otherwise identified to the Exchange Agent, then, prior to the release of such certificates, you must also submit:

- the serial numbers of the particular certificates to be withdrawn; and
- a signed notice of withdrawal with signatures guaranteed by an eligible institution unless you are an eligible guarantor institution.

If Outstanding Notes have been tendered pursuant to the procedures for book-entry transfer described above, any notice of withdrawal must specify the name and number of the account at the book-entry transfer facility to be credited with the withdrawn Outstanding Notes and otherwise comply with the procedures of the facility. We will determine all questions as to the validity, form and eligibility, including time of receipt of notices of withdrawal, and our determination will be final and binding on all parties. Any Outstanding Notes so withdrawn will be deemed not to have been validly tendered for exchange for purposes of the Exchange Offers. Any Outstanding Notes that have been tendered for exchange but that are not exchanged for any reason will be returned to their holder, without cost to the holder, or, in the case of book-entry transfer, the Outstanding Notes will be credited to an account at the book-entry transfer facility, promptly after withdrawal, rejection of tender or termination of the Exchange Offers. Properly withdrawn Outstanding Notes may be retendered by following the procedures described under "—Procedures for Tendering Outstanding Notes" above at any time prior to the expiration of the Exchange Offers.

Exchange Agent

The Bank of New York Mellon Trust Company, N.A. has been appointed as the Exchange Agent for the Exchange Offers. The Bank of New York Mellon Trust Company, N.A. also acts as trustee under the Indenture. You should direct all executed letters of transmittal and all questions and requests for assistance with respect to accepting or withdrawing from the Exchange Offers, requests for additional copies of this prospectus or of the letter of transmittal and requests for notices of guaranteed delivery to the Exchange Agent addressed as follows:

By Mail, Hand or Courier	*By Facsimile Transmission (eligible institutions only)*
The Bank of New York Mellon Trust Company, N.A., as Exchange Agent c/o The Bank of New York Mellon Corporation Corporate Trust Operations-Reorganization Unit 111 Sanders Creek Parkway East Syracuse, NY 13057 Attn: Eric Herr Tel: 315-414-3362	(732) 667-9408 To Confirm by Telephone (315-414-3362) Email: CT_REORG_UNIT_INQUIRIES@BNYMELLON.COM

If you deliver the letter of transmittal to an address other than the one set forth above or transmit instructions via facsimile to a number other than the one set forth above, that delivery or those instructions will not be effective.

Fees and Expenses

The registration rights agreement provides that we will bear all expenses in connection with the performance of our obligations relating to the registration of the Exchange Notes and the conduct of the Exchange Offers. These expenses include registration and filing fees, accounting and legal fees and printing costs, among others. We will pay the Exchange Agent reasonable and customary fees for its services and reasonable out-of-pocket expenses. We will also reimburse brokerage houses and other custodians, nominees and fiduciaries for customary mailing and handling expenses incurred by them in forwarding this prospectus and related documents to their clients that are holders of Outstanding Notes and for handling or tendering for such clients.

We have not retained any dealer-manager in connection with the Exchange Offers and will not pay any fee or commission to any broker, dealer, nominee or other person for soliciting tenders of Outstanding Notes pursuant to the Exchange Offers.

Accounting Treatment

We will record the Exchange Notes in our accounting records at the same carrying value as the Outstanding Notes, which is the aggregate principal amount as reflected in our accounting records on the date of exchanges. Accordingly, we will not recognize any gain or loss for accounting purposes upon the consummation of the Exchange Offers. We will record the costs of the Exchange Offers as incurred.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchanges of Outstanding Notes under the Exchange Offers. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if:

- certificates representing Outstanding Notes for principal amounts not tendered or accepted for exchange are to be delivered to, or are to be issued in the name of, any person other than the registered holder of Outstanding Notes tendered;

- tendered Outstanding Notes are registered in the name of any person other than the person signing the letter of transmittal; or

- a transfer tax is imposed for any reason other than the exchange of Outstanding Notes under the Exchange Offers.

If satisfactory evidence of payment of such taxes is not submitted with the letter of transmittal, the amount of such transfer taxes will be billed to that tendering holder.

Holders who tender their Outstanding Notes for exchange will not be required to pay any transfer taxes. However, holders who instruct us to register Exchange Notes in the name of, or request that Outstanding Notes not tendered or not accepted in the Exchange Offers be returned to, a person other than the registered tendering holder will be required to pay any applicable transfer tax.

Consequences of Failure to Exchange

If you do not exchange your Outstanding Notes for Exchange Notes under the Exchange Offers, your Outstanding Notes will remain subject to the restrictions on transfer of such Outstanding Notes:

- as set forth in the legend printed on the Outstanding Notes as a consequence of the issuance of the Outstanding Notes pursuant to the exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws; and

- as otherwise set forth in the offering memorandum distributed in connection with the private offerings of the Outstanding Notes.

In general, you may not offer or sell your Outstanding Notes unless they are registered under the Securities Act or if the offer or sale is exempt from registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreement, we do not intend to register resales of the Outstanding Notes under the Securities Act.

Other

Participating in the Exchange Offers is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered Outstanding Notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any Outstanding Notes that are not tendered in the Exchange Offers or to file a registration statement to permit resales of any untendered Outstanding Notes.

DESCRIPTION OF THE EXCHANGE NOTES

The following summary description sets forth certain terms and provisions of the Exchange Notes. Because this description is a summary, it does not describe every aspect of the Exchange Notes or the Indenture (as defined below) under which the Exchange Notes will be issued, and which is filed as an exhibit to the registration statement of which this prospectus is a part. The Indenture and its associated documents contain the full legal text of the matters described in this section. This summary is subject to and qualified in its entirety by reference to all of the provisions of the Exchange Notes and the Indenture, including definitions of certain terms used in the Indenture. We also include references in parentheses to certain sections of the Indenture. Whenever we refer to particular sections or defined terms of the Indenture in this prospectus, such sections or defined terms are incorporated by reference herein.

General

The form and terms of the Exchange Notes are identical in all material respects to the form and terms of the Outstanding Notes except the Exchange Notes will:

- be registered under the Securities Act;
- not be subject to the restrictions on transfer applicable to the Outstanding Notes (except for the limited restrictions described under "-Form; Transfers and Exchanges");
- not be entitled to any registration rights that are applicable to the Outstanding Notes under the registration rights agreement, including any right to additional interest; and
- bear different CUSIP numbers.

We will issue the Exchange Notes under an indenture dated as of November 1, 2016 between us and The Bank of New York Mellon Trust Company, N.A., as trustee, as supplemented by supplemental indentures or company orders (the "Indenture"). This prospectus briefly outlines some provisions of the Indenture. If you would like more information on these provisions, you should review the Indenture and any supplemental indentures or company orders. See "AVAILABLE INFORMATION" on how to locate these documents. You may also review these documents at the Trustee's offices at 2 North LaSalle Street, 7th Floor, Chicago, Illinois 60602 following reasonable advance notice and during normal business hours.

The Indenture does not limit the amount of notes that may be issued. The Indenture permits us to issue notes in one or more series or tranches upon the approval of our board of directors and as provided in one or more company orders or supplemental indentures. Each series of notes may differ as to their terms. We may from time to time, without consent of the holders of the Exchange Notes, issue additional notes having the same ranking, interest rate, maturity and other terms as the Exchange Notes (except for the issue date and the issue price). These additional notes, together with the Exchange Notes, will be a single series of notes under the Indenture.

The Exchange Notes are our senior unsecured obligations and will rank equally with our senior unsecured obligations. As of March 1, 2018, we had no secured indebtedness outstanding.

The Exchange Notes will be denominated in U.S. dollars and we will pay principal and interest in U.S. dollars. The Exchange Notes of each series will be issuable in minimum denominations of $2,000 and in multiples of $1,000 in excess thereof. The Exchange Notes will not be subject to any conversion, amortization or sinking fund.

The Exchange Notes will not be guaranteed by, or otherwise be obligations of, AEP or any of its direct or indirect subsidiaries other than AEPTCo.

Principal Amount, Maturity and Interest

The 2026 Exchange Notes will be initially issued in aggregate principal amount of $125,030,000 and the 2047 Exchange Notes will be initially issued in aggregate principal amount of $500,000,000.

The 2026 Exchange Notes will mature and become due and payable, together with any accrued and unpaid interest, on

December 1, 2026 and will bear interest at the rate of 3.10% per annum from December 1, 2017 until December 1, 2026. The 2047 Exchange Notes will mature and become due and payable, together with any accrued and unpaid interest, on December 1, 2047 and will bear interest at the rate of 3.75% per annum from September 28, 2017 until December 1, 2047.

Interest on each note will be payable semi-annually in arrears on each June 1 and December 1 and at redemption, if any, or maturity. The initial interest payment date is June 1, 2018. Each payment of interest shall include interest accrued through the day before such interest payment date. Interest on the Exchange Notes will be computed on the basis of a 360-day year consisting of twelve 30-day months.

We will pay interest on the Exchange Notes of each series (other than interest payable at redemption, if any, or maturity) in immediately available funds to the owners of the Exchange Notes as of the Regular Record Date (as defined below) for each interest payment date. We will pay the principal of the Exchange Notes and any premium and interest payable at redemption, if any, or maturity in immediately available funds at the office of the Trustee at 2 North LaSalle Street, 7th Floor, Chicago, Illinois 60602.

If any interest payment date, redemption date or the maturity is not a Business Day (as defined below), we will pay all amounts due on the next succeeding Business Day and no additional interest will be paid.

The "Regular Record Date" will be the May 15 or November 15 prior to the relevant interest payment date, whether or not such day is a Business Day.

"Business Day" means any day that is not a day on which banking institutions in New York City are authorized or required by law or regulation to close.

Optional Redemption

We may redeem any or all series of the Exchange Notes in whole or in part by delivering written notice to the noteholders no more than 60, and not less than 30, days prior to redemption. If we do not redeem all the Exchange Notes of a series at one time, the Trustee will select the Exchange Notes to be redeemed in a manner it determines to be fair, provided that if the Exchange Notes are represented by one or more global notes, the Exchange Notes to be redeemed will be selected in accordance with the procedures of DTC.

At any time prior to September 1, 2026, we may redeem the 2026 Exchange Notes either as a whole or in part at a redemption price equal to the greater of (1) 100% of the principal amount of the 2026 Exchange Notes being redeemed and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the 2026 Exchange Notes being redeemed that would be due if such 2026 Exchange Notes matured on September 1, 2026 (excluding the portion of any such interest accrued to, but excluding, the date of redemption), discounted (for purposes of determining present value) to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 15 basis points, plus, in each case, accrued and unpaid interest thereon to, but excluding, the date of redemption.

At any time prior to June 1, 2047, we may redeem the 2047 Exchange Notes either as a whole or in part at a redemption price equal to the greater of (1) 100% of the principal amount of the 2047 Exchange Notes being redeemed and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the 2047 Exchange Notes being redeemed that would be due if such 2047 Exchange Notes matured on June 1, 2047 (excluding the portion of any such interest accrued to, but excluding, the date of redemption), discounted (for purposes of

determining present value) to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 15 basis points, plus, in each case, accrued and unpaid interest thereon to, but excluding, the date of redemption.

At any time on or after September 1, 2026, we may redeem the 2026 Exchange Notes in whole or in part at 100% of the principal amount of the 2026 Exchange Notes being redeemed, plus accrued and unpaid interest thereon to but excluding the date of redemption. At any time on or after June 1, 2047, we may redeem the 2047 Exchange Notes in whole or in part at 100% of the principal amount of the 2047 Exchange Notes being redeemed, plus accrued and unpaid interest thereon to but excluding the date of redemption.

"Comparable Treasury Issue," applicable to each series, means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term ("remaining life") of the Exchange Notes (assuming, for this purpose, that the 2026 Exchange Notes matured on September 1, 2026 and the 2047 Exchange Notes matured on June 1, 2047) that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining life of the Exchange Notes.

"Comparable Treasury Price," applicable to each series, means, with respect to any redemption date, (1) the average of the Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest of such Reference Treasury Dealer Quotations, or (2) if we obtain fewer than four of such Reference Treasury Dealer Quotations, the average of all such quotations.

"Independent Investment Banker" means one of the Reference Treasury Dealers appointed by us and notified by us to the Trustee.

"Reference Treasury Dealer" means a primary U.S. Government securities dealer or dealers selected by us and notified by us to the Trustee.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us and notified to the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us and the Trustee by such Reference Treasury Dealer at or before 3:30 p.m., New York City time, on the third Business Day preceding such redemption date.

"Treasury Rate" means, with respect to any redemption, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, calculated using a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

Agreement to Provide Information

So long as any Exchange Notes are outstanding under the Indenture, during such periods as we are not subject to the periodic reporting requirements of Section 13 or 15(d) of the Exchange Act, we will furnish to prospective purchasers of the Notes, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act for compliance with Rule 144A.

Certain Covenants

Consolidation, Merger or Sale

We may merge or consolidate with any corporation or sell all or substantially all of our assets as an entirety as long as the successor or purchaser of such assets expressly assumes, the payment of principal, and premium, if any, and interest on the Exchange Notes.

Limitation on Consolidated Priority Debt

The Company covenants that so long as any of the Exchange Notes are outstanding that it will not permit Consolidated Priority Debt to exceed 10% of Consolidated Tangible Net Assets for a period in excess of five consecutive Business Days.

Limitation on Liens

The Company covenants that for so long as any of the Exchange Notes are outstanding that it will not create or suffer to exist or permit any of its subsidiaries to create or suffer to exist any Secured Debt, unless, at the same time, the Exchange Notes that are outstanding are also secured by such Lien on an equal and ratable basis; provided, however, the foregoing does not limit

(i) Permitted Liens; and

(ii) Any other Lien not covered in clause (i) as long as immediately after the creation of such Lien the aggregate principal amount of Secured Debt does not exceed 10% of Consolidated Tangible Net Assets.

Definitions

"Consolidated Priority Debt" means all Priority Debt of the Company and its subsidiaries determined on a consolidated basis eliminating inter-company items.

"Consolidated Tangible Net Assets" means the total of all assets (including revaluations thereof as a result of commercial appraisals, price level restatement or otherwise) appearing on the most recent quarterly or annual, as applicable, consolidated balance sheet of the Company and its consolidated subsidiaries, net of applicable reserves and deductions, but excluding goodwill, trade names, trademarks, patents, unamortized debt discount and all other like intangible assets (which term shall not be construed to include such revaluations), less the aggregate of the consolidated current liabilities of the Company and its consolidated subsidiaries appearing on such balance sheet.

"Debt" means any indebtedness for borrowed money.

"Lien or Liens" means any mortgage, pledge, security interest, or other lien on any utility properties or tangible assets, including, without limitation, the capital stock or comparable equity interests of its subsidiaries, now owned or hereafter acquired by the Company or its subsidiaries.

"Permitted Liens" means

- Liens on property existing at the time of acquisition or construction of such property (or created within one year after completion of such acquisition or construction), whether by purchase, merger, construction or otherwise, or to secure the payment of all or any part of the purchase price or construction cost thereof, including the extension of any Liens to repairs, renewals, replacements, substitutions, betterments, additions, extensions and improvements then or thereafter made on the property subject thereto;

- Any extensions, renewals or replacements (or successive extensions, renewals or replacements), in whole or in part, of Liens permitted by the foregoing clauses;

- The pledge of any bonds or other securities at any time issued under any of the Secured Debt permitted by the above clauses; and

- The creation or existence of leases (operating or capital) made, or existing on property acquired, in the ordinary course of business.

"Priority Debt" means, without duplication, any Debt of the Company's subsidiaries; *provided* that there shall be excluded from any calculation of Priority Debt, (i) the Debt of any subsidiary owing to the Company or a subsidiary of the Company, and (ii) the Debt of any entity which becomes a subsidiary after the issuance of the Exchange Notes and any extension, renewal or refunding thereof; *provided* that such Debt was not incurred in contemplation of such entity becoming a subsidiary.

"Secured Debt" means any Debt of the Company or any of its subsidiaries secured by a Lien (other than a Permitted Lien).

Events of Default

"Event of Default" means, with respect to any particular series of notes, any of the following:

- failure to pay for three business days the principal of (or premium, if any, on) any note of that series when due and payable;
- failure to pay for 30 days any interest on any note of that series when due and payable;
- failure to perform any other requirements in any notes of that series, or in the Indenture in regard to such notes, for 90 days after notice; or
- certain events of bankruptcy or insolvency.

An Event of Default for a particular series of notes does not necessarily mean that an Event of Default has occurred for any other series of notes issued under the Indenture. If an Event of Default occurs and continues, the Trustee or the holders of at least 33% of the principal amount of the notes of the series affected may require us to repay the entire principal of the notes of such series immediately (Repayment Acceleration). In most instances, the holders of at least a majority in aggregate principal amount of the notes of the affected series may rescind a previously triggered Repayment Acceleration. However, if we cause an Event of Default because we have failed to pay (unaccelerated) principal, premium, if any, or interest, Repayment Acceleration may be rescinded only if we have first cured our default by depositing with the Trustee enough money to pay all (unaccelerated) past due amounts and penalties, if any.

The Trustee must within 90 days after a default occurs, notify the holders of the notes of the series of default unless such default has been cured or waived. We are required to file an annual certificate with the Trustee, signed by an officer, concerning our compliance with the conditions and covenants of the Indenture and specifying any default by us under any provisions of the Indenture.

Subject to the provisions of the Indenture relating to its duties in case of default, the Trustee shall be under no obligation to exercise any of its rights or powers under the Indenture at the request, order or direction of any holders unless such holders offer the Trustee indemnity satisfactory to the Trustee. Subject to the provisions of the Indenture, the holders of a majority in principal amount of the notes of any series may direct the time, method and place of conducting any proceedings for any remedy available to, or exercising any trust or power conferred on, the Trustee with respect to such notes.

Modification of Indenture

Under the Indenture, our rights and obligations and the rights of the holders of any notes may be changed. Any change affecting the rights of the holders of any series of notes requires the consent of the holders of not less than a majority in aggregate principal amount of the outstanding Exchange Notes of all series affected by the change, voting as one class. However, we cannot change the terms of payment of principal or interest, or a reduction in the percentage required for changes or a waiver of default, unless the affected holders consent. We may issue additional series of notes and take other action that does not affect the rights of holders of any series by executing supplemental indentures without the consent of any noteholders.

Legal Defeasance

We will be discharged from our obligations on the Exchange Notes of any series at any time if:

- we deposit with the Trustee sufficient cash or government securities to pay the principal, interest, any premium and any other sums due to the stated maturity date or a redemption date of the Exchange Notes of the series,

- immediately after such deposit, no default exists, and

- we deliver to the Trustee an opinion of counsel, who may be an employee of, or counsel for, the Company, stating that the United States federal income tax obligations of noteholders of that series will not change as a result of our performing the action described above, with such opinion based upon a ruling of the IRS issued to us or a change of law or regulation occurring after November 16, 2016 in the case of the 2026 Exchange Notes, and after September 25, 2017 in the case of the 2047 Exchange Notes .

If this happens, the noteholders of the series will not be entitled to the benefits of the Indenture except for registration of transfer and exchange of Exchange Notes and replacement of lost, stolen or mutilated Exchange Notes.

Covenant Defeasance

We will be discharged from our obligations under any restrictive covenant applicable to the Exchange Notes of a particular series if:

- we deposit with the Trustee cash or government securities sufficient to pay the principal, interest and any premium due on or prior to maturity,

- immediately after such deposit, no default exists, and

- we deliver to the Trustee an opinion of counsel, who may be an employee of, or counsel for, the Company, stating that the United States federal income tax obligations of noteholders of that series will not change as a result of our performing the action described above.

If this happens, any later breach of that particular restrictive covenant will not result in Repayment Acceleration. If we cause an Event of Default apart from breaching that restrictive covenant, there may not be sufficient money or government obligations on deposit with the Trustee to pay all amounts due on the Exchange Notes of that series. In that instance, we would remain liable for such amounts.

Governing Law

The Indenture and Exchange Notes will be governed by the laws of the State of New York.

Concerning the Trustee

We and our affiliates use or will use some of the banking services of the Trustee and other services of its affiliates in the normal course of business.

Book-Entry Only Issuance-The Depository Trust Company

DTC will act as the initial securities depository for the Exchange Notes. The Exchange Notes issued in exchange for Outstanding Notes will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered note certificate will be issued for each issue of the Exchange Notes, each in the aggregate principal amount of such issue, and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com. The contents of such website do not constitute part of this prospectus.

Purchases of Exchange Notes under the DTC system must be made by or through Direct Participants, which will receive a credit for the Exchange Notes on DTC's records. The ownership interest of each actual purchaser of each note ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Exchange Notes are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Exchange Notes, except in the event that use of the book-entry system for the Exchange Notes is discontinued.

To facilitate subsequent transfers, all Exchange Notes deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of Exchange Notes with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Exchange Notes; DTC's records reflect only the identity of the Direct Participants to whose accounts such Exchange Notes are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of Exchange Notes may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Exchange Notes, such as redemptions, tenders, defaults, and proposed amendments to the Exchange Notes documents. For example, Beneficial Owners of Exchange Notes may wish to ascertain that the nominee holding the Exchange Notes for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the Exchange Notes are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Exchange Notes unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to us as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Exchange Notes are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds and distributions on the Exchange Notes will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from us or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with Exchange Notes held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of such Participant and not of DTC, the Trustee or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds and distributions to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is our or the Trustee's responsibility, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Exchange Notes purchased or tendered, through its Participant, to the Tender/Remarketing Agent, and shall effect delivery of such Exchange Notes by causing the Direct Participant to transfer the Participant's interest in the Exchange Notes, on DTC's records, to the Tender/Remarketing Agent. The requirement for physical delivery of the Exchange Notes in connection with an optional tender or a mandatory purchase will be deemed satisfied when the ownership rights in the Exchange Notes are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Exchange Notes to the Tender/Remarketing Agent's DTC account.

DTC may discontinue providing its services as depository with respect to the Exchange Notes at any time by giving reasonable notice to us. Under such circumstances, in the event that a successor depository is not obtained, note certificates are required to be printed and delivered.

We may decide to discontinue use of the system of book-entry only transfers through DTC (or a successor securities depository). In that event, note certificates will be printed and delivered to DTC.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that we believe to be reliable, but we take no responsibility for the accuracy thereof.

MATERIAL UNITED STATES FEDERAL INCOME TAX CONSEQUENCES OF THE EXCHANGE OFFERS

The exchange of Outstanding Notes for Exchange Notes of the corresponding series in the Exchange Offers will not constitute a taxable event to holders for United States federal income tax purposes. Consequently, no gain or loss will be recognized by a holder upon receipt of an Exchange Note, the holding period of the Exchange Note will include the holding period of the Outstanding Note exchanged therefor and the basis of the Exchange Note will be the same as the basis of the Outstanding Note immediately before the exchange.

In any event, persons considering the exchange of Outstanding Notes for Exchange Notes should consult their own tax advisors concerning the United States federal income tax consequences in light of their particular situations as well as any consequences arising under the laws of any other taxing jurisdiction.

PLAN OF DISTRIBUTION

Each broker-dealer that receives Exchange Notes for its own account pursuant to the Exchange Offers must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Notes received in exchange for Outstanding Notes where such Outstanding Notes were acquired as a result of market-making activities or other trading activities. We have agreed that, for a period of 180 days after the Expiration Date, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale. In addition, all dealers effecting transactions in the Exchange Notes may be required to deliver a prospectus.

We will not receive any proceeds from any sale of Exchange Notes by broker-dealers. Exchange Notes received by broker-dealers for their own account pursuant to the Exchange Offers may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the Exchange Notes or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer and/or the purchasers of any such Exchange Notes. Any broker-dealer that resells Exchange Notes that were received by it for its own account pursuant to the Exchange Offers and any broker or dealer that participates in a distribution of such Exchange Notes may be deemed to be an "underwriter" within the meaning of the Securities Act, and any profit on any such resale of Exchange Notes and any commission or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that, by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act.

For a period of 180 days after the Expiration Date, we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. Subject to certain limitations set forth in the registration rights agreement, we have agreed to pay all expenses incident to the Exchange Offers (including the expenses of one counsel for the holders of the Outstanding Notes) other than commissions or concessions of any brokers or dealers and will indemnify you (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

LEGAL MATTERS

Thomas G. Berkemeyer or William E. Johnson, Associate General Counsel and Senior Counsel, respectively, of American Electric Power Service Corporation, our service company affiliate, will issue an opinion about the legality of the Exchange Notes for us.

EXPERTS

The financial statements of AEP Transmission Company, LLC as of December 31, 2017 and for the year ended December 31, 2017 included in this Prospectus and the financial statement schedule of AEP Transmission Company, LLC as of December 31, 2017 and for the year ended December 31, 2017 included in the registration statement have been so included in reliance on the reports of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of AEP Transmission Company, LLC for years ended December 31, 2016 and 2015 included in this Prospectus and the related financial statement schedule for years ended December 31, 2016 and 2015 included elsewhere in the Registration Statement, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein. Such financial statements and financial statement schedule are included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

AVAILABLE INFORMATION

We have filed with the SEC a registration statement on Form S-4 under the Securities Act with respect to the Exchange Notes. This prospectus, which forms a part of the registration statement, does not contain all of the information set forth in the registration statement. For further information with respect to us and the Exchange Notes, reference is made to the registration statement. Statements contained in this prospectus as to the contents of any contract or other document are not complete.

We have agreed to make certain information available to holders of the Notes, as described under "Description of the Exchange Notes-Agreement to Provide Information."

The Company is subject to the informational requirements of the Exchange Act and, in accordance therewith, files reports and other information with the SEC. These reports and other information can be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also read and copy these SEC filings by visiting the SEC's website at http://www.sec.gov.

You may request additional copies of our reports or copies of our other SEC filings at no cost by writing or telephoning us at the following address:

AEP Transmission Company, LLC
1 Riverside Plaza
Columbus, Ohio 43215
Attention: Investor Relations
Telephone: (614) 716-1000

This prospectus is only for AEP Transmission Company, LLC ("AEPTCo"). The notes to the financial statements are a combined presentation for AEP Transmission Company, LLC and certain of its affiliates, and include amounts and discussion relating to such affiliates. However, none of such affiliates is a guarantor or obligor on the Outstanding Notes or the Exchange Notes, for which AEPTCo is and will be the sole obligor, and the reports of the independent registered public accounting firms only apply to the notes to the financial statements as they relate to AEPTCo. Accordingly, unless indicated that the information in the notes applies to all entities or specifically to AEPTCo, such information should be disregarded, because it pertains only to affiliates who will not be guarantors or obligors on the Exchange Notes.

2017 Annual Report

AEP Transmission Company, LLC and Subsidiaries

Audited Financial Statements

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 Renewables	AEP Renewables, LLC, a wholly-owned subsidiary of Energy Supply formed for the purpose of providing utility scale wind and solar projects whose power output is sold via long-term power purchase agreements to other utilities, cities and corporations.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Utilities	AEP Utilities, Inc., a former subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. Effective December 31, 2016, TCC and TNC were merged into AEP Utilities, Inc. Subsequently following this merger, the assets and liabilities of CSW Energy, Inc. were transferred to a competitive affiliate company and AEP Utilities, Inc. was renamed AEP Texas Inc.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas market.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, and its consolidated State Transcos, a subsidiary of AEP Transmission Holdco.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
ALJ	Administrative Law Judge.
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.
CAIR	Clean Air Interstate Rule.
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, 2,278 MW nuclear plant owned by I&M.

Term	Meaning
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, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X and DCC Fuel XI consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	Desert Sky Wind Farm, a 160.5 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DIR	Distribution Investment Rider.
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.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco 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.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
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.
kV	Kilovolt.

KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
Market Based Mechanism	An order from the LPSC established to evaluate proposals to construct or acquire generating capacity. The LPSC directs that the market based mechanism shall be a request for proposal competitive solicitation process.
MISO	Midwest Independent Transmission System Operator.

Term	Meaning
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
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.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
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.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
Price River	Rights and interests in certain coal reserves located in Carbon County, Utah.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Putnam	Rights and interests in certain coal reserves located in Putnam, Mason and Jackson Counties, West Virginia.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo,

	PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
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.
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.
SCR	Selective Catalytic Reduction, NO_x reduction technology at Rockport Plant.
SEC	U.S. Securities and Exchange Commission.

Term	Meaning
SEET	Significantly Excessive Earnings Test.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
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.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	Formerly AEP Texas North Company, now a division of AEP Texas.
TRA	Tennessee Regulatory Authority.
Transition Funding	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.
Trent	Trent Wind Farm, a 150 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
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.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project which includes the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

AEP TRANSMISSION COMPANY, LLC
AND SUBSIDIARIES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Member of
AEP Transmission Company, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of AEP Transmission Company, LLC and its subsidiaries as of December 31, 2017, and the related consolidated statements of income, of changes in member's equity, and of cash flows for the year then ended, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 22, 2018

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Shareholder of
AEP Transmission Company, LLC

We have audited the accompanying consolidated balance sheet of AEP Transmission Company, LLC and subsidiaries (the "Company") as of December 31, 2016, and the related consolidated statements of income, changes in member's equity, and cash flows for each of the two years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in Item 21 at Exhibit 99(e). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Transmission Company, LLC and subsidiaries as of December 31, 2016, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
April 4, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of AEP Transmission Company, LLC and Subsidiaries (AEPTCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEPTCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEPTCo's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEPTCo's internal control over financial reporting was effective as of December 31, 2017.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEPTCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEPTCo to provide only management's report in this annual report.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016 and 2015
(in millions)

	Years Ended December 31,		
	2017	2016	2015
REVENUES			
Transmission Revenues	$ 141.9	$ 110.4	$ 84.3
Sales to AEP Affiliates	580.5	367.5	225.6
Other Revenues	0.8	0.1	0.3
TOTAL REVENUES	723.2	478.0	310.2
EXPENSES			
Other Operation	60.1	37.0	22.4
Maintenance	8.5	6.7	5.0
Depreciation and Amortization	97.1	65.9	42.4
Taxes Other Than Income Taxes	109.7	88.3	66.0
TOTAL EXPENSES	275.4	197.9	135.8
OPERATING INCOME	447.8	280.1	174.4
Other Income (Expense):			
Interest Income	1.2	0.4	0.1
Allowance for Equity Funds Used During Construction	52.3	52.3	53.0
Interest Expense	(68.0)	(46.0)	(34.6)

INCOME BEFORE INCOME TAX EXPENSE	433.3	286.8	192.9
Income Tax Expense	147.2	94.1	60.0
NET INCOME	$ 286.1	$ 192.7	$ 132.9

See Notes to Financial Statements of Registrants beginning on page F-16.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Years Ended December 31, 2017, 2016 and 2015
(in millions)

	Paid-in Capital	Retained Earnings	Total Member's Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2014	$ 964.0	$ 177.0	$ 1,141.0
Capital Contributions from Member	279.0		279.0
Net Income		132.9	132.9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2015	1,243.0	309.9	1,552.9
Capital Contributions from Member	212.0		212.0
Net Income		192.7	192.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	1,455.0	502.6	1,957.6
Capital Contributions from Member	361.6		361.6
Net Income		286.1	286.1
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	$ 1,816.6	$ 788.7	$ 2,605.3

See Notes to Financial Statements of Registrants beginning on page F-16.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2017 and 2016
(in millions)

	December 31, 2017	December 31, 2016
CURRENT ASSETS		
Advances to Affiliates	$ 146.3	$ 67.1
Accounts Receivable:		
Customers	19.1	11.3
Affiliated Companies	93.2	66.6
Miscellaneous	1.3	—
Total Accounts Receivable	113.6	77.9

Materials and Supplies	13.6	5.0
Accrued Tax Benefits	46.6	26.0
Prepayments and Other Current Assets	7.6	2.8
TOTAL CURRENT ASSETS	327.7	178.8
TRANSMISSION PROPERTY		
Transmission Property	5,336.1	3,973.5
Other Property, Plant and Equipment	131.4	99.4
Construction Work in Progress	1,312.7	981.3
Total Transmission Property	6,780.2	5,054.2
Accumulated Depreciation and Amortization	170.4	99.6
TOTAL TRANSMISSION PROPERTY – NET	6,609.8	4,954.6
OTHER NONCURRENT ASSETS		
Regulatory Assets	11.7	112.3
Deferred Property Taxes	117.8	102.2
Deferred Charges and Other Noncurrent Assets	1.1	1.9
TOTAL OTHER NONCURRENT ASSETS	130.6	216.4
TOTAL ASSETS	$ 7,068.1	$ 5,349.8

See Notes to Financial Statements of Registrants beginning on page F-16.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
December 31, 2017 and 2016

	December 31,	
	2017	**2016**
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 15.7	$ 4.1
Accounts Payable:		
General	473.2	289.7
Affiliated Companies	52.9	43.1
Long-term Debt Due Within One Year – Nonaffiliated	50.0	—
Accrued Taxes	225.4	191.8
Accrued Interest	15.0	10.5
Other Current Liabilities	4.1	10.9
TOTAL CURRENT LIABILITIES	836.3	550.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,500.4	1,932.0
Deferred Income Taxes	601.7	862.1
Regulatory Liabilities	493.7	44.0
Deferred Credits and Other Noncurrent Liabilities	30.7	4.0

TOTAL NONCURRENT LIABILITIES	3,626.5	2,842.1
TOTAL LIABILITIES	4,462.8	3,392.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEMBER'S EQUITY		
Paid-in Capital	1,816.6	1,455.0
Retained Earnings	788.7	502.6
TOTAL MEMBER'S EQUITY	2,605.3	1,957.6
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 7,068.1	$ 5,349.8

See Notes to Financial Statements of Registrants beginning on page F-16.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016 and 2015
(in millions)

	Years Ended December 31,		
	2017	**2016**	**2015**
OPERATING ACTIVITIES			
Net Income	$ 286.1	$ 192.7	$ 132.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	97.1	65.9	42.4
Deferred Income Taxes	272.8	223.1	183.2
Allowance for Equity Funds Used During Construction	(52.3)	(52.3)	(53.0)
Property Taxes	(15.6)	(15.3)	(25.6)
Change in Other Noncurrent Assets	9.8	(2.8)	1.8
Change in Other Noncurrent Liabilities	27.3	4.4	0.6
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(34.5)	(22.6)	(26.3)
Materials and Supplies	(8.6)	(5.0)	—
Accounts Payable	9.8	14.3	(3.5)
Accrued Taxes, Net	13.0	143.8	(53.6)
Accrued Interest	4.5	2.6	0.9
Other Current Assets	(4.8)	0.1	(0.4)
Other Current Liabilities	0.2	—	—
Net Cash Flows from Operating Activities	604.8	548.9	199.4
INVESTING ACTIVITIES			
Construction Expenditures	(1,513.4)	(1,159.5)	(1,007.8)
Change in Advances to Affiliates, Net	(79.2)	29.0	65.4
Acquisitions of Assets	(9.1)	(6.5)	(1.1)
Other Investing Activities	6.1	2.0	3.4

Net Cash Flows Used for Investing Activities	(1,595.6)	(1,135.0)	(940.1)
FINANCING ACTIVITIES			
Capital Contributions from Member	361.6	212.0	279.0
Issuance of Long-term Debt – Nonaffiliated	617.6	686.9	449.0
Change in Advances from Affiliates, Net	11.6	(12.8)	12.7
Retirement of Long-term Debt – Nonaffiliated	—	(300.0)	—
Net Cash Flows from Financing Activities	990.8	586.1	740.7
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 61.2	$ 42.0	$ 32.5
Net Cash Paid (Received) for Income Taxes	(107.3)	(235.1)	(11.2)
Noncash Acquisitions Under Capital Leases	0.2	—	—
Construction Expenditures Included in Current Liabilities as of December 31,	473.7	298.3	208.0

See Notes to Financial Statements of Registrants beginning on page F-16.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

This prospectus is only for AEP Transmission Company, LLC. The notes to the financial statements include amounts and discussion relating to American Electric Power Company, Inc., AEP Texas Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Unless indicated that the notes apply to all entities or specifically to AEP Transmission Company, LLC, they are not part of this prospectus. Additionally, any information regarding entities other than AEP Transmission Company, LLC should be disregarded. The reports of the independent registered public accounting firms only apply to the notes as they relate to AEP Transmission Company LLC. None of such other entities is a guarantor or obligor on the Outstanding Notes or the Exchange Notes, for which AEPTCo is and will be the sole obligor.

The notes to financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise.

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

ORGANIZATION

The Registrants engage in the generation, transmission and distribution of electric power. The Registrant Subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP provides competitive electric and gas supply for residential, commercial and industrial customers in deregulated electricity markets and also provides energy management solutions throughout the United States, including energy efficiency services through its independent retail electric supplier.

The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, AEP operates competitive wind and solar farms. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

Disposition of AEP River Operations (Applies to AEP)

In October 2015, AEP signed an agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated third party. The sale closed in November 2015. The results of operations of AEPRO have been classified as Discontinued Operations on the statements of income for the prior periods presented. The transaction was accounted for in accordance with the accounting guidance for “Presentation of Financial Statements and Property, Plant and Equipment.” Material disclosures within the notes to the financial statements exclude amounts related to Discontinued Operations for all periods presented. See “AEPRO (Corporate and Other)” section of Note 7 for additional information.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP’s public utility subsidiaries’ rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants’ affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrants’ wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that the Registrants have “market power” in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants’ retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who

have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers pay for certain deferred generation-related costs through non-bypassable charges. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has no active REPs in ERCOT. AEP’s nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT.

The FERC also regulates the Registrants’ wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Ohio for OPCo, in Virginia for APCo and in Michigan for I&M. AEP Texas’ retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for AEP’s seven wholly-owned transmission subsidiaries within the AEP Transmission Holdco segment are based on formula rates included in the applicable RTO’s OATT that are cost-based.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the SIA, Operating Agreement, Transmission Agreement and Transmission Coordination

Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA and the Bridge Agreement, see Note 16 - Related Party Transactions for additional information.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for AEP Texas include the Registrant Subsidiary, its wholly-owned subsidiaries and Transition Funding (a substantially-controlled VIE). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a substantially-controlled VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (substantially-controlled VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and Ohio Phase-in-Recovery Funding (a substantially-controlled VIE). The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a substantially-controlled VIE). Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. AEP, AEP Texas, I&M, PSO and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included in the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Note 18 - Property, Plant and Equipment.

Accounting for the Effects of Cost-Based Regulation

The Registrants' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Accounting for the Impacts of Tax Reform

Given the significance of the legislative changes resulting from Tax Reform, the timing of its enactment and the widespread applicability to registrants, the SEC staff recognized the potential challenges faced by registrants when reflecting the effects of Tax Reform in their 2017 financial statements. Accordingly, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017, which provides for a one year measurement period to complete the accounting for Tax Reform.

The Registrants have made reasonable estimates for the measurement and accounting for the impacts of Tax Reform and these estimates are reflected in the December 31, 2017 financial statements as provisional amounts. While the Registrants were able to make reasonable estimates of the impact of Tax Reform, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative temporary differences or as a result of additional guidance or technical corrections that may be issued by the IRS or regulatory state commissions that impacts management's interpretation and assumptions utilized. See "Federal Tax Reform" section of Note 12 for additional information.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Restricted Cash (Applies to AEP, AEP Texas, APCo and OPCo)

Restricted Cash primarily includes funds held by trustees for the payment of securitization bonds.

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following tables provide a reconciliation of Cash, Cash Equivalents and Restricted Cash reported within the balance sheet that sum to the total of the same amounts shown on the statement of cash flows:

	December 31, 2017			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 214.6	$ 2.0	$ 2.9	$ 3.1
Restricted Cash	198.0	155.2	16.3	26.6
Total Cash, Cash Equivalents and Restricted Cash	$ 412.6	$ 157.2	$ 19.2	$ 29.7

	December 31, 2016			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 210.5	$ 0.6	$ 2.7	$ 3.1
Restricted Cash	193.0	146.3	15.8	27.2
Total Cash, Cash Equivalents and Restricted Cash	$ 403.5	$ 146.9	$ 18.5	$ 30.3

Other Temporary Investments (Applies to AEP)

Other Temporary Investments include securities available for sale, including marketable securities that management intends to hold for less than one year and investments by its protected cell of EIS.

Management classifies investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. AEP does not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, management considers, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR and AEP's non-regulated ownership share of

Oklaunion Plant, which is carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See "Sale of Receivables – AEP Credit" section of Note 14 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers (Applies to Registrant Subsidiaries)

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant customers which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Centrica, Just Energy and Reliant Energy	**2017 (a)**	**2016**	**2015**
Percentage of Total Revenues	35%	46%	53%
Percentage of Accounts Receivable – Customers	31%	42%	43%

(a) Just Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	**2017**	**2016**	**2015**
Percentage of Total Revenues	80%	77%	73%

Percentage of Total Accounts Receivable	82%	86%	77%

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Emission Allowances and Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record emission allowances and renewable energy credits (RECs) at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For AEP's competitive generation business, management records allowances and RECs at the lower of cost or market. The Registrants follow the inventory model for these allowances and RECs. Allowances and RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. Allowances and RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of allowances and RECs are reported in the Operating Activities section of the statements of cash flows. Allowances are consumed in the production of energy, and RECs are consumed to meet applicable state renewable portfolio standards and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of emission allowances is included in Vertically Integrated Utilities Revenues on AEP's statements of income and in Electric Generation, Transmission and Distribution Revenues because of its integral nature to the production process of energy and the Registrants' revenue optimization strategy for their operations. The net margin on sales of emission allowances and RECs affects the determination of deferred fuel or deferred emission allowance and REC costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation

assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheet.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Nonregulated operations generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at original cost (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. The Registrants record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for “Capitalization of Interest.”

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

The accounting guidance for “Fair Value Measurements and Disclosures” establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs (Applies to all Registrants except AEP Texas and AEPTCo)

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable.

Changes in fuel costs, including purchased power in Kentucky for KPCo, Indiana and Michigan for I&M, in Ohio (through the ESP related to standard service offer load served through auctions) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO, in Virginia and West Virginia for APCo and in West Virginia for WPCo are reflected in rates in a timely manner generally through the FAC. In Ohio, changes in fuel costs and purchased power costs, incurred from 2009 through 2011, continue to be recovered in rider rates that will terminate in December 2018. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo and WPCo, all of the non-merchant margins from off-system sales are given to customers through the FAC. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are tested for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is written off as a charge against income.

Electricity Supply and Delivery Activities

The Registrants recognize revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates. In accordance with the accounting guidance for "Regulated Operations - Revenue Recognition", the Registrants recognize revenue and expense related to the rate true-ups immediately following the annual FERC filings. Any portion of the true-ups applicable to an affiliated company is

recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets.

Most of the power produced at the generation plants is sold to PJM or SPP. The Registrants also purchase power from PJM and SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrants record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

The Registrants engage in power, capacity and, to a lesser extent, natural gas marketing as major power producers and participants in electricity and natural gas markets. The Registrants also engage in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrants recognize revenues and expenses from marketing and risk management transactions that are not derivatives upon delivery of the commodity. The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event the Registrants designate a cash flow hedge, the effective portion of the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrants subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. In regulated jurisdictions, the ineffective portion is deferred as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Levelization of Nuclear Refueling Outage Costs (Applies to AEP and I&M)

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

The Registrants expense maintenance costs as incurred. If it becomes probable that the Registrants will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulated jurisdictions, the Registrants defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. The Registrants revalued deferred tax assets and liabilities at the new federal corporate income tax rate of 21% in December 2017. See Note 12 for additional information related to Tax Reform.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits (ITC) were historically accounted for under the flow-through method, except where regulatory commissions reflected ITC in the rate-making process. In 2016, AEP and subsidiaries changed accounting for the recognition of ITC and elected to apply the preferred deferral methodology. Retrospective application is not necessary for reporting periods prior to 2016 as the financial impact to AEP and subsidiaries was immaterial.

Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

The Registrants account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrants classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes (Applies to all Registrants except AEPTCo)

As agents for some state and local governments, the Registrants collect from customers certain excise taxes levied by those state or local governments on customers. The Registrants do not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Goodwill and Intangible Assets (Applies to AEP)

When AEP acquires businesses, management records the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, goodwill is recorded. Goodwill and intangible assets with indefinite lives are not amortized. Management tests acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. Management tests goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods. AEP amortizes intangible assets with finite lives over their respective estimated lives to their estimated residual values. Management also reviews the lives of the amortizable intangibles with finite lives on an annual basis.

Pension and OPEB Plans (Applies to all Registrants except AEPTCo)

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Registrant Subsidiaries account for their participation in the AEP sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%
OPEB Plans Assets	**Target**
Equity	49%
Fixed Income	49%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds (Applies to AEP and I&M)

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the “Nuclear Contingencies” section of Note 6 for additional discussion of nuclear matters. See “Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal” section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss) (Applies to all Registrants except AEPTCo)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2017, AEP had performance units and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, performance units awarded prior to 2017 are settled in cash and restricted stock units are settled in AEP common shares, except for restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vest to executive officers, which are settled in cash. All performance units and restricted stock units awarded after January 1, 2017 will be settled in AEP common shares. The impact of AEP’s stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance units granted to employees under the 2015 LTIP. AEP career shares are equal in value to shares of AEP common stock and become payable to executives after their service ends. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. In 2017 the SORP was changed to provide all future AEP career share payments to be made in AEP common stock, rather than cash.

Performance units awarded after January 1, 2017 are classified as temporary equity in the mezzanine section of the balance sheet. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity.

AEP compensates their non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2017, 2016 and 2015 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2017, 2016 and 2015, compensation cost is included in Net Income for the performance units, career shares, restricted stock units and the non-employee director's stock units. Compensation cost may also be capitalized. See Note 15 for additional information.

Equity Investment of Unconsolidated Affiliates (Applies to AEP and SWEPCo)

AEP includes equity in earnings from equity method investments in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. SWEPCo includes equity in earnings from an equity method investment in Equity Earnings (Loss) of Unconsolidated Subsidiary on the statements of income. AEP and SWEPCo regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

AEP has two significant equity method investments, ETT and DHLC. ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. Berkshire Hathaway Energy, a nonaffiliated entity, holds a 50% membership interest in ETT, AEP Transmission Holdco holds a 49.5% membership interest in ETT and AEP Transmission Partner holds the remaining 0.5% membership interest in ETT. As a result, AEP, through its wholly-owned subsidiaries, holds a 50% membership interest in ETT. As of December 31, 2017, AEP's investment in ETT was $664 million which is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP's equity earnings associated with ETT were $82 million for the year ended December 31, 2017. See "Non-Consolidated Significant Variable Interest" section of Note 17 for more information about DHLC.

Earnings Per Share (EPS) (Applies to AEP)

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

The following table presents AEP's basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31,		
	2017	2016	2015
	(in millions, except per share data)		

		$/share		$/share		$/share
Income from Continuing Operations	$ 1,928.9		$ 620.5		$ 1,768.6	
Less: Net Income Attributable to Noncontrolling Interests	16.3		7.1		5.2	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$ 1,912.6		$ 613.4		$ 1,763.4	
Weighted Average Number of Basic Shares Outstanding	491.8	$ 3.89	491.5	$ 1.25	490.3	$ 3.59
Weighted Average Dilutive Effect of Stock-Based Awards	0.8	(0.01)	0.2	—	0.3	—
Weighted Average Number of Diluted Shares Outstanding	492.6	$ 3.88	491.7	$ 1.25	490.6	$ 3.59

There were no antidilutive shares outstanding as of December 31, 2017, 2016 and 2015.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2017, 2016 and 2015:

2017

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,709.1	$ 221.1	$ 97.1	$ 407.6	$ 203.1	$ 200.9	$ 131.4	$ 217.2
Amortization of Certain Securitized Assets	275.9	231.4	—	—	—	44.4	—	—
Amortization of Regulatory Assets and Liabilities	12.2	(2.4)	—	0.3	7.8	(19.4)	(1.0)	0.2
Total Depreciation and Amortization	$ 1,997.2	$ 450.1	$ 97.1	$ 407.9	$ 210.9	$ 225.9	$ 130.4	$ 217.4

2016

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,688.5	$ 204.0	$ 65.9	$ 387.6	$ 183.9	$ 202.3	$ 122.6	$ 196.6
Amortization of Certain Securitized Assets	254.6	210.3	—	—	—	44.3	—	—
Amortization of Regulatory Assets and Liabilities	19.2	(0.4)	—	0.9	7.8	(8.0)	7.6	(0.1)
Total Depreciation and Amortization	$ 1,962.3	$ 413.9	$ 65.9	$ 388.5	$ 191.7	$ 238.6	$ 130.2	$ 196.5

2015

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo

	(in millions)							
Depreciation and Amortization of Property, Plant and Equipment	$ 1,674.3	$ 193.3	$ 42.4	$ 385.6	$ 193.5	$ 184.4	$ 108.6	$ 190.7
Amortization of Certain Securitized Assets	318.9	275.5	—	—	—	43.3	—	—
Amortization of Regulatory Assets and Liabilities	16.5	0.1	—	3.2	4.9	(10.2)	8.9	1.3
Total Depreciation and Amortization	$ 2,009.7	$ 468.9	$ 42.4	$ 388.8	$ 198.4	$ 217.5	$ 117.5	$ 192.0

Supplementary Cash Flow Information (Applies to AEP)

	Years Ended December 31,		
Cash Flow Information	**2017**	**2016**	**2015**
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 858.3	$ 848.5	$ 857.2
Income Taxes	(1.1)	29.5	120.2
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	60.7	86.1	150.2
Construction Expenditures Included in Current Liabilities as of December 31,	1,330.8	858.0	741.4
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	71.8	—	51.6
Construction Expenditures Included in Noncurrent Assets as of December 31,	—	—	10.5
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	—	2.1	37.9
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.6	0.7	2.2

2. NEW ACCOUNTING PRONOUNCEMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

During FASB’s standard-setting process and upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrants’ business. The following pronouncements will impact the financial statements.

ASU 2014-09 “Revenue from Contracts with Customers” (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 changing 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.

Management analyzed the impact of the new revenue standard and related ASUs. During 2016 and 2017, revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Additionally, the new standard did not give rise to any changes in current accounting systems. Management continues to develop disclosures to comply with the requirements of ASU 2014-09, including disclosures of significant disaggregated revenue streams, and information about fixed performance obligations that are unsatisfied (or partially unsatisfied) as of the end of a reporting period.

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach. The adoption of ASU 2014-09 did not have a material impact on results of operations, financial position or cash flows. Management will continue to actively participate in informal industry forums throughout the period of initial adoption.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 revising 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. For equity investments that do not have a readily determinable fair value, entities are permitted to elect a practicality exception and measure the investment at cost, less impairment, plus or minus observable price changes. 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 sheets 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 for certain provisions. Management adopted ASU 2016-01 effective January 1, 2018, by means of a cumulative-effect adjustment to the balance sheet. The adoption of ASU 2016-01 resulted in an immaterial impact on results of operations and financial position of AEP, and no impact to results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 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; however, the FASB is currently evaluating whether to provide reporting entities with an additional expedient to adopt the new lease requirements through a cumulative-effect adjustment in the period of adoption. Accordingly, management continues to monitor these standard-setting activities that may impact the transition requirements of the lease standard.

Management continues to analyze the impact of the new lease standard. During 2016 and 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Multiple lease system options were also evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.

Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Evaluation of new lease contracts continues and the process of implementing a compliant lease system solution began in the third quarter of 2017. Management expects the new standard to impact financial position and, at this time, cannot estimate the impact. Management expects no impact to results of operations or cash flows.

Management continues to monitor unresolved industry implementation issues, including items related to easements and right-of-ways, and will analyze the related impacts to lease accounting. In this regard, to address stakeholder concerns about the costs and complexity of complying with the transition provisions of the new lease standard, the FASB issued ASU 2018-01 in January 2018. This ASU provides an optional transition practical expedient that allows companies to exclude in their evaluation of Topic 842 existing or expired land easements that were not previously accounted for as leases under Topic 840, which reduces the volume of contracts requiring evaluation. Management intends to elect this practical expedient upon adoption of ASU 2016-02.

Management continues to monitor FASB's ongoing standard-setting activities that may result in the issuance of additional targeted improvements to the new lease guidance. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 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 previous 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.

Management adopted ASU 2016-09 effective January 1, 2017. As a result of the adoption of this guidance, management made an accounting policy election to recognize the effect of forfeitures in compensation cost when they occur. There was an immaterial impact on results of operations and financial position and no impact on cash flows at adoption.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 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.

ASU 2016-18 "Restricted Cash" (ASU 2016-18)

In November 2016, the FASB issued ASU 2016-18 clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows.

The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. Management adopted ASU 2016-18 for the 2017 Annual Report and applied the new standard retrospectively for all periods presented. See the "Restricted Cash" section of Note 1 for the effect of adoption on cash flows for each Registrant.

ASU 2017-07 "Compensation - Retirement Benefits" (ASU 2017-07)

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented in the statements of income separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor. For 2017, AEP's actual non-service cost components were a credit of $72 million, of which approximately 41% was capitalized.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Management adopted ASU 2017-07 effective January 1, 2018.

ASU 2017-12 "Derivatives and Hedging" (ASU 2017-12)

In August 2017, the FASB issued ASU 2017-12 amending the recognition and presentation requirements for hedge accounting activities. The objectives are to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and reduce the complexity of applying hedge accounting. Under the new standard, the concept of recognizing hedge ineffectiveness within the statements of income for cash flow hedges, which has historically been immaterial to AEP, will be eliminated. In addition, certain required tabular disclosures relating to fair value and cash flow hedges will be modified.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted for any interim or annual period after August 2017. Management is analyzing the impact of this new standard, including the possibility of early adoption, and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows.

ASU 2018-02 "Reclassification of Certain Tax Effects from AOCI" (ASU 2018-02)

In February 2018, the FASB issued ASU 2018-02 allowing a reclassification from AOCI to Retained Earnings for stranded tax effects resulting from Tax Reform. Under existing accounting guidance for "Income Taxes", deferred tax assets and liabilities must be adjusted for the effect of a change in tax laws or rates with the effect included in income from continuing operations in the reporting period that includes the enactment date. This guidance is applicable for the tax effects of items in AOCI that were originally recognized in Other Comprehensive Income. As a result and absent the new guidance in this ASU, the tax effects of items within AOCI do not reflect the newly enacted corporate tax rate. While the reclassification between AOCI and Retained Earnings is optional under the new guidance, the ASU also requires certain new disclosure requirements regardless of whether the reclassification is made.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted. The new guidance must be applied either retrospectively to each period (or periods) in which the income tax effects of Tax Reform related to items remaining in AOCI are recognized, or at the beginning of the period of adoption. Management is analyzing the impact of this new standard, including the possibility of early adoption.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the financial statements.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2017, 2016 and 2015. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)
Change in Fair Value Recognized in AOCI	(20.4)	1.6	3.5	—	86.5	71.2
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale	28.8	—	—	—	—	28.8
Interest Expense	—	1.5	—	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	—	(19.6)	—	(19.6)
Amortization of Actuarial (Gains)/Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	23.2	1.5	—	1.7	—	26.4
Income Tax (Expense) Credit	8.1	0.4	—	0.6	—	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15.1	1.1	—	1.1	—	17.3
Net Current Period Other Comprehensive Income (Loss)	(5.3)	2.7	3.5	1.1	86.5	88.5
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2015	$ (5.2)	$ (17.2)	$ 7.1	$ 139.9	$ (251.7)	$ (127.1)
Change in Fair Value Recognized in AOCI	(14.6)	—	1.3	—	(14.7)	(28.0)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues	(21.4)	—	—	—	—	(21.4)
Purchased Electricity for Resale	16.4	—	—	—	—	16.4
Interest Expense	—	2.4	—	—	—	2.4
Amortization of Prior Service Cost (Credit)	—	—	—	(19.4)	—	(19.4)
Amortization of Actuarial (Gains)/Losses	—	—	—	20.3	—	20.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(5.0)	2.4	—	0.9	—	(1.7)
Income Tax (Expense) Credit	(1.7)	0.9	—	0.3	—	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(3.3)	1.5	—	0.6	—	(1.2)

Net Current Period Other Comprehensive Income (Loss)	(17.9)	1.5	1.3	0.6	(14.7)	(29.2)
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges			Pension and OPEB		
	Commodity	**Interest Rate**	**Securities Available for Sale**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)			
Balance in AOCI as of December 31, 2014	$ 1.6	$ (19.1)	$ 7.7	$ 138.7	$ (232.0)	$ (103.1)
Change in Fair Value Recognized in AOCI	5.6	—	(0.6)	—	(25.7)	(20.7)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues	(48.1)	—	—	—	—	(48.1)
Purchased Electricity for Resale	29.1	—	—	—	—	29.1
Interest Expense	—	2.9	—	—	—	2.9
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains)/Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(19.0)	2.9	—	1.8	—	(14.3)
Income Tax (Expense) Credit	(6.6)	1.0	—	0.6	—	(5.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(12.4)	1.9	—	1.2	—	(9.3)
Net Current Period Other Comprehensive Income (Loss)	(6.8)	1.9	(0.6)	1.2	(25.7)	(30.0)
Balance in AOCI as of Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	—	6.0	6.0
Balance in AOCI as of December 31, 2015	$ (5.2)	$ (17.2)	$ 7.1	$ 139.9	$ (251.7)	$ (127.1)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	**Amoritization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.3	0.4	—	1.7
Income Tax (Expense) Credit	0.4	0.1	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.9	0.3	—	1.2
Net Current Period Other Comprehensive Income (Loss)	0.9	0.3	1.1	2.3
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge - Interest Rate	Pension and OPEB		Total
		Amortization of Deferred Costs	Changes in Funded Status	
	(in millions)			
Balance in AOCI as of December 31, 2015	$ (6.5)	$ 3.9	$ (14.6)	$ (17.2)
Change in Fair Value Recognized in AOCI	(0.1)	—	0.9	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	1.8	—	—	1.8
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.8	0.4	—	2.2
Income Tax (Expense) Credit	0.6	0.1	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.2	0.3	—	1.5
Net Current Period Other Comprehensive Income (Loss)	1.1	0.3	0.9	2.3
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedge - Interest Rate	Pension and OPEB		Total
		Amortization of Deferred Costs	Changes in Funded Status	
	(in millions)			
Balance in AOCI as of December 31, 2014	$ (7.7)	$ 3.6	$ (14.8)	$ (18.9)
Change in Fair Value Recognized in AOCI	(0.1)	—	0.2	0.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.9	0.5	—	2.4
Income Tax (Expense) Credit	0.6	0.2	—	0.8
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	0.3	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.2	0.3	0.2	1.7
Balance in AOCI as of December 31, 2015	$ (6.5)	$ 3.9	$ (14.6)	$ (17.2)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	11.6	11.6
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains)/Losses	—	3.4	—	3.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.1)	(1.8)	—	(2.9)
Income Tax (Expense) Credit	(0.4)	(0.6)	—	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.7)	(1.2)	—	(1.9)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.2)	11.6	9.7
Balance in AOCI as of December 31, 2017	$ 2.2	$ 14.8	$ (15.7)	$ 1.3

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ 3.6	$ 17.4	$ (23.8)	$ (2.8)
Change in Fair Value Recognized in AOCI	—	—	(3.5)	(3.5)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains)/Losses	—	3.0	—	3.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.1)	(2.1)	—	(3.2)
Income Tax (Expense) Credit	(0.4)	(0.7)	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.7)	(1.4)	—	(2.1)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.4)	(3.5)	(5.6)
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedge - Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2014	$ 3.9	$ 19.2	$ (18.1)	$ 5.0
Change in Fair Value Recognized in AOCI	—	—	(5.7)	(5.7)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	(0.4)	—	—	(0.4)
Amortization of Prior Service Cost (Credit)	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains)/Losses	—	2.3	—	2.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)	(2.8)	—	(3.2)
Income Tax (Expense) Credit	(0.1)	(1.0)	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)	(1.8)	—	(2.1)
Net Current Period Other Comprehensive Income (Loss)	(0.3)	(1.8)	(5.7)	(7.8)
Balance in AOCI as of December 31, 2015	$ 3.6	$ 17.4	$ (23.8)	$ (2.8)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains)/Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.0	—	—	2.0
Income Tax (Expense) Credit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Pension and OPEB	
	Amortization	Changes in

	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)
Change in Fair Value Recognized in AOCI	—	—	(0.8)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains)/Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.0	—	—	2.0
Income Tax (Expense) Credit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	(0.8)	0.5
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2014	$ (14.4)	$ 5.1	$ (5.0)	$ (14.3)
Change in Fair Value Recognized in AOCI	—	—	(3.5)	(3.5)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	1.7	—	—	1.7
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains)/Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.7	—	—	1.7
Income Tax (Expense) Credit	0.6	—	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.1	—	—	1.1
Net Current Period Other Comprehensive Income (Loss)	1.1	—	(3.5)	(2.4)
Balance in AOCI as of December 31, 2015	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.7)

Reclassifications from AOCI, before Income Tax (Expense) Credit		(1.7)
Income Tax (Expense) Credit		(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		(1.1)
Net Current Period Other Comprehensive Income (Loss)		(1.1)
Balance in AOCI as of December 31, 2017	$	1.9

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge - Interest Rate	
	(in millions)	
Balance in AOCI as of December 31, 2015	$	4.3
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense		(1.9)
Reclassifications from AOCI, before Income Tax (Expense) Credit		(1.9)
Income Tax (Expense) Credit		(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		(1.3)
Net Current Period Other Comprehensive Income (Loss)		(1.3)
Balance in AOCI as of December 31, 2016	$	3.0

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedge - Interest Rate	
	(in millions)	
Balance in AOCI as of December 31, 2014	$	5.6
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense		(2.0)
Reclassifications from AOCI, before Income Tax (Expense) Credit		(2.0)
Income Tax (Expense) Credit		(0.7)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		(1.3)
Net Current Period Other Comprehensive Income (Loss)		(1.3)
Balance in AOCI as of December 31, 2015	$	4.3

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

Cash Flow Hedge -

	Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.3)
Income Tax (Expense) Credit	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2017	$ 2.6

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2015	$ 4.2
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.2)
Income Tax (Expense) Credit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2016	$ 3.4

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2014	$ 5.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.2)
Income Tax (Expense) Credit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)

Balance in AOCI as of December 31, 2015	$	4.2

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB		
		Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	4.7	4.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	2.2	—	—	2.2
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains)/Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.2	(1.1)	—	1.1
Income Tax (Expense) Credit	0.8	(0.4)	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.4	(0.7)	—	0.7
Net Current Period Other Comprehensive Income (Loss)	1.4	(0.7)	4.7	5.4
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge - Interest Rate	Pension and OPEB		
		Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (9.1)	$ 2.6	$ (2.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	2.7	—	—	2.7
Amortization of Prior Service Cost (Credit)	—	(1.8)	—	(1.8)
Amortization of Actuarial (Gains)/Losses	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.7	(1.1)	—	1.6
Income Tax (Expense) Credit	1.0	(0.4)	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.7	(0.7)	—	1.0
Net Current Period Other Comprehensive Income (Loss)	1.7	(0.7)	(1.0)	—
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2014	$ (11.1)	$ 3.6	$ —	$ (7.5)
Change in Fair Value Recognized in AOCI	—	—	(2.9)	(2.9)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense	3.1	—	—	3.1
Amortization of Prior Service Cost (Credit)	—	(1.9)	—	(1.9)
Amortization of Actuarial (Gains)/Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	3.1	(1.5)	—	1.6
Income Tax (Expense) Credit	1.1	(0.5)	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2.0	(1.0)	—	1.0
Net Current Period Other Comprehensive Income (Loss)	2.0	(1.0)	(2.9)	(1.9)
Balance in AOCI as of December 31, 2015	$ (9.1)	$ 2.6	$ (2.9)	$ (9.4)

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

Impact of Tax Reform

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which will impact outstanding rate and regulatory matters. For details on the impact of Tax Reform, see Note 12 - Income Taxes.

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

AEP Texas Interim Transmission and Distribution Rates

As of December 31, 2017, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2017, subject to review, are estimated to be $763 million. A base rate review could produce a refund if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition. In November 2017, the PUCT published a proposed rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for rate proceedings. The proposal would require AEP Texas to file for a comprehensive rate review no later than April 1, 2019. In January 2018, AEP Texas submitted comments on the rule proposing, among other changes, that its initial filing due date under the rule be changed from April 1, 2019 to May 1, 2019.

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. AEP Texas has a PUCT approved catastrophe reserve in base rates and can defer incremental storm expenses. AEP Texas currently recovers approximately $1 million of storm costs annually through base rates. As of December 31, 2017, the total balance of AEP Texas' deferred storm costs is approximately $123 million, inclusive of approximately $100 million of incremental storm expenses recorded as a regulatory asset related to Hurricane Harvey. As of December 31, 2017, AEP Texas has recorded approximately $133 million of capital expenditures related to Hurricane Harvey. Also, as of December 31, 2017, AEP Texas has received $10 million in insurance proceeds, which were applied to the regulatory asset and property, plant and equipment. Management, in conjunction with the insurance adjusters, is reviewing all damages to determine the extent of coverage for additional insurance reimbursement. Any future insurance recoveries received will be applied to and will offset the regulatory asset and property, plant and equipment, as applicable. Management believes the amount recorded as a regulatory asset is probable of recovery and AEP Texas is currently evaluating recovery options for the regulatory asset. The other named 2017 hurricanes did not have a material impact on AEP's operations. If the ultimate costs of the incident are not recovered by insurance or through the regulatory process, it would have an adverse effect on future net income, cash flows and financial condition.

<u>APCo Rate Matters</u> (Applies to AEP and APCo)

Virginia Legislation Affecting Biennial Reviews

In 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 precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

In February 2018, legislation separately passed the Virginia House of Delegates and the Senate of Virginia and, if enacted and signed into law by the Governor in its present form, will: (a) require APCo to not recover $10 million of fuel expenses incurred after July 1, 2018, (b) reduce APCo's base rates by $50 million annually, on an interim basis and subject to true-up, effective July 30, 2018 related to Tax Reform and (c) require an adjustment in APCo's base rates on April 1, 2019 to reflect actual annual reductions in corporate income taxes due to Tax Reform. APCo's next base rate review in 2020 will now include a review of earnings for test years 2017-2019, with triennial reviews of APCo's base rates and earnings thereafter instead of biennial reviews. The current VA legislative session is scheduled to adjourn in March 2018. Either a biennial review of 2018-2019 or a triennial review of 2017-2019 could reduce future net income and cash flows and impact financial condition.

<u>ETT Rate Matters</u> (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. Through December 31, 2017, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $746 million. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. In November 2017, the PUCT published a proposed rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for rate proceedings. The proposal requires ETT to file for a comprehensive rate review no later than February 1, 2021. In January 2018, ETT submitted comments recommending changes to the proposed draft rule.

<u>I&M Rate Matters</u> (Applies to AEP and I&M)

2017 Indiana Base Rate Case

In July 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity with the annual increase to be implemented after June 2018. Upon implementation, this proposed annual increase would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018 for a credit adjustment rider related to the timing of estimated in-service dates of certain capital expenditures. The proposed annual increase includes $78 million related to increased annual depreciation rates and an $11 million increase related to the amortization of certain Cook Plant and Rockport Plant regulatory assets. The increase in depreciation rates includes a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant, including the Cook Plant Life Cycle Management Project.

In November 2017, various intervenors filed testimony that included annual revenue increase recommendations ranging from $125 million to $152 million. The recommended returns on common equity ranged from 8.65% to 9.1%. In addition, certain parties recommended longer recovery periods than I&M proposed for recovery of regulatory assets and depreciation expenses related to Rockport Plant, Units 1 and 2. In January 2018, in response to a January 2018 IURC request related to the impact of Tax Reform on I&M's pending base rate case, I&M filed updated schedules supporting a $191 million annual increase in Indiana base rates if the effect of Tax Reform was included in the cost of service.

In February 2018, I&M and all parties to the case, except one industrial customer, filed a Stipulation and Settlement Agreement for a $97 million annual increase in Indiana rates effective July 1, 2018 subject to a temporary offsetting reduction to customer bills through December 2018 for a credit rider related to the timing of estimated in-service dates of certain capital expenditures. The one industrial customer agreed to not oppose the Stipulation and Settlement Agreement. The difference between I&M's requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement is primarily due to lower federal income taxes as a result of the reduction in the federal income tax rate due to Tax Reform, the feedback of credits for excess deferred income taxes, a 9.95% return on equity, longer recovery periods of regulatory assets, lower depreciation expense primarily for meters, and an increase in the sharing of off-system sales margins with customers from 50% to 95%. I&M will also refund $4 million from July through December 2018 for the impact of Tax Reform for the period January through June 2018. A hearing at the IURC is scheduled for March 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project. Additionally, the total proposed increase includes incremental costs related to the Cook Plant Life Cycle Management Program and increased vegetation management expenses.

In October 2017, the MPSC staff and intervenors filed testimony. The MPSC staff recommended an annual net revenue increase of $49 million including proposed retirement dates of 2028 for both Rockport Plant, Units 1 (from 2044) and 2 (from 2022), a reduced capacity charge and a return on common equity of 9.8%. The intervenors proposed certain adjustments to I&M's request including no change to the current 2044 retirement date of Rockport Plant, Unit 1, a market based capacity charge effective February 2019 for up to 10% of I&M's Michigan customers, but did not address an annual net revenue increase. The intervenors' recommended returns on common equity ranged from 9.3% to 9.5%. A hearing at the MPSC was held in November 2017.

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including the intervenors' proposed capacity charge and staff's depreciation rates for Rockport Plant and a return on common equity of 9.8%. If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity charge is approximately $9 million. An order is expected in the first half of 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant, Unit 2 Selective Catalytic Reduction

In October 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2 by December 2019. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. As of December 31, 2017, total costs incurred related to this project, including AFUDC, were approximately $23 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to I&M and KPCo and will be subject to future regulatory approval for recovery.

In February 2017, the Indiana Office of Utility Consumer Counselor (OUCC) and other parties filed testimony with the IURC. The OUCC recommended approval of the CPCN but also stated that any decision regarding recovery of any under-depreciated plant due to retirement should be fully investigated in a base rate case, not in a tracker or other abbreviated proceeding. The other parties recommended either denial of the CPCN or approval of the CPCN with conditions including a cap on the amount of SCR costs allowed to be recovered in the rider and limitations on other costs related to legal issues involving the Rockport Plant, Unit 2 lease. A hearing at the IURC was held in March 2017. An order from the IURC is pending. In July 2017, I&M filed a motion with the U.S. District Court for the Southern District of Ohio to remove the requirement to install SCR technology at Rockport Plant, Unit 2, which plaintiffs opposed. The district court has delayed the deadline for installation of the SCR technology until June 2020. In January 2018, I&M filed a supplemental motion with the U.S. District Court for the Southern District of Ohio proposing to install the SCR at Rockport Plant, Unit 2 and achieve the final SO_2 emission cap applicable to the plant under the consent decree by the end of 2020, before the expiration of the initial lease term. Responsive filings were filed in February 2018 and a decision is anticipated in the first quarter of 2018.

KPCo Rate Matters (Applies to AEP)

2017 Kentucky Base Rate Case

In June 2017, KPCo filed a request with the KPSC for a $66 million annual increase in Kentucky base rates based upon a proposed 10.31% return on common equity with the increase to be implemented no later than January 2018. The proposed increase included: (a) lost load since KPCo last changed base rates in July 2015, (b) incremental costs related to OATT charges from PJM not currently recovered from retail ratepayers, (c) increased depreciation expense including updated Big Sandy Plant, Unit 1 depreciation rates using a proposed retirement date of 2031, (d) recovery of other Big Sandy Plant, Unit 1 generation costs currently recovered through a retail rider and (e) incremental purchased power costs. Additionally, KPCo requested a $4 million annual increase in environmental surcharge revenues. In August 2017, KPCo submitted a supplemental filing with the KPSC that decreased the proposed annual base rate revenue request to $60 million. The modification was due to lower interest expense related to June 2017 debt refinancings.

In November 2017, KPCo filed a non-unanimous settlement agreement with the KPSC. The settlement agreement included a proposed annual base rate increase of $32 million based upon a 9.75% return on common equity.

In January 2018, the KPSC issued an order approving the non-unanimous settlement agreement with certain modifications resulting in an annual revenue increase of $12 million, effective January 2018, based on a 9.7% return on equity. The KPSC's primary revenue requirement modification to the settlement agreement was a $14 million annual revenue reduction for the decrease in the corporate federal income tax rate due to Tax Reform. The KPSC approved: (a) the deferral of $50 million of

Rockport Plant Unit Power Agreement expenses for the years 2018 through 2022, with recovery of the deferral to be addressed in KPCo's next base rate case, (b) the recovery/return of 80% of certain annual PJM OATT expenses above/below the corresponding level recovered in base rates, (c) KPCo's commitment to not file a base rate case for three years and (d) increased depreciation expense based upon updated Big Sandy Plant, Unit 1 depreciation rates using a 20-year depreciable life.

In February 2018, KPCo filed with the KPSC for rehearing of the January 2018 base case order and requested an additional $2.3 million of annual revenue increases related to: (a) the calculation of federal income tax expense, (b) recovery of purchased power costs associated with forced outages and (c) capital structure adjustments. Also in February 2018, an intervenor filed for rehearing recommending that the reduced corporate federal income tax rate, as a result of Tax Reform, be reflected in lower purchased power expense related to the Rockport UPA. It is anticipated that the KPSC will rule upon this rehearing request in the first quarter of 2018.

<u>OPCo Rate Matters</u> (Applies to AEP and OPCo)

Ohio Electric Security Plan Filings

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

In 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the DIR, effective June 2015 through May 2018. The proposal also involved a PPA rider that would include OPCo's OVEC contractual entitlement (OVEC PPA) and would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA.

In 2015 and 2016, the PUCO issued orders in this proceeding. As part of the issued orders, the PUCO approved (a) the DIR with modified rate caps, (b) recovery of OVEC-related net margin incurred beginning June 2016, (c) potential additional contingent customer credits of up to $15 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. 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 MWs and a wind energy project(s) of at least 500 MWs, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. In December 2016, in accordance with the stipulation agreement, OPCo filed a carbon reduction plan that focused on fuel diversification and carbon emission reductions. In April 2017, the PUCO rejected all pending rehearing requests and the orders are all now final. In June 2017, intervenors filed appeals to the Supreme Court of Ohio stating that the PUCO's approval of the OVEC PPA was unlawful and does not provide customers with rate stability.

In November 2016, OPCo refiled its amended ESP extension application and supporting testimony, consistent with the terms of the modified and approved stipulation agreement and based upon a 2016 PUCO order. The amended filing proposed to extend the ESP through May 2024 and included (a) an extension of the OVEC PPA rider, (b) a proposed 10.41% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's DIR and (e) the addition of various new riders, including a Renewable Resource Rider.

In August 2017, OPCo and various intervenors filed a stipulation agreement with the PUCO. The stipulation extends the term of the ESP through May 2024 and includes: (a) an extension of the OVEC PPA rider, (b) a proposed 10% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) rate caps related to OPCo's DIR ranging from $215 million to $290 million for the periods 2018 through 2021 and (e) the addition of various new riders, including a Smart City Rider and a Renewable Generation Rider. DIR rate caps will be reset in OPCo's next distribution base rate case which must be filed by June 2020.

In October 2017, intervenor testimony opposing the stipulation agreement was filed recommending: (a) a return on common equity to not exceed 9.3% for riders earning a return on capital investments, (b) that OPCo should file a base distribution case concurrent with the conclusion of the current ESP in May 2018 and (c) denial of certain new riders proposed in OPCo's ESP extension. The stipulation is subject to review by the PUCO. A hearing at the PUCO was held in November 2017. An order from the PUCO is expected in the first quarter of 2018.

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.

2016 SEET Filing

Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. Significantly excessive earnings are measured by whether the earned return on common equity of the electric utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk.

In December 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In May 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016 based upon actual earnings data for the comparable utilities risk group.

In January 2018, PUCO staff filed testimony that OPCo did not have significantly excessive earnings. Also in January 2018, an intervenor filed testimony recommending a $53 million refund to customers.

In February 2018, OPCo and PUCO staff filed a stipulation agreement in which both parties agreed that OPCo did not have significantly excessive earnings in 2016.

In February 2018, a procedural schedule was issued by the PUCO. A hearing is scheduled for April 2018 and management expects to receive an order in the second quarter of 2018. While management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group, or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

2017 Oklahoma Base Rate Case

In June 2017, PSO filed an application for a base rate review with the OCC that requested an increase in annual revenues of $156 million, less an $11 million refund obligation, for a net increase of $145 million based upon a proposed 10% return on common equity. The proposed base rate increase includes (a) environmental compliance investments, including recovery of previously deferred environmental compliance related costs currently recorded as regulatory assets, (b) Advanced Metering Infrastructure investments, (c) additional capital investments and costs to serve PSO's customers, and (d) an annual $42 million depreciation rate increase due primarily to shorter service lives and lower net salvage estimates. As part of this filing, consistent with the OCC's final order in its previous base rate case, PSO requested recovery through 2040 of Northeastern Plant, Unit 3, including the environmental control investment, and the net book value of Northeastern Plant, Unit 4 that was retired in 2016. As of December 31, 2017, the net book value of Northeastern Plant, Unit 4 was $81 million.

In January 2018, the OCC issued a final order approving a net increase in Oklahoma annual revenues of $84 million, which was then reduced by $32 million to $52 million to account for changes as a result of Tax Reform, based upon a return on common equity of 9.3%. The final order also included approval for recovery, with a debt return for investors, of the net book value of Northeastern Plant Unit 4 and an annual depreciation expense increase of $19 million, including requested recovery through 2040 of Northeastern Plant, Unit 3. PSO anticipates implementing new rates in March 2018 billings.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of previously recorded regulatory disallowances in 2013. The resulting annual base rate increase was approximately $52 million. In June 2017, the Texas District Court upheld the PUCT's 2014 order. In July 2017, intervenors filed appeals with the Texas Third Court of Appeals.

If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included (a) approval to recover the Texas jurisdictional share of environmental investments placed in service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in the fourth quarter, SWEPCo (a) recorded an impairment charge of $19 million, which includes $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that will be surcharged to customers and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expenses. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues will be collected by the end of 2018. In addition, SWEPCo is required to file a refund tariff within 120 days to reflect the difference between rates collected under the final order and the rates that would be collected under Tax Reform.

Louisiana Turk Plant Prudence Review

Beginning January 2013, SWEPCo's formula rates, including the Louisiana jurisdictional share (approximately 33%) of the Turk Plant, have been collected subject to refund pending the outcome of a prudence review of the Turk Plant investment, which was placed into service in December 2012. In October 2017, the LPSC staff filed testimony contending that SWEPCo failed to continue to evaluate the suspension or cancellation of the Turk Plant during its construction period. In January 2018, SWEPCo and the LPSC staff filed a settlement, subject to LPSC approval, providing for a $19 million pretax write off of the Louisiana jurisdictional share of previously capitalized Turk Plant costs and a $10 million rate refund provision for previously collected revenues associated with the disallowed portion of the Turk Plant. Based on the agreement, management concluded that the disallowance was probable resulting in a $23 million pretax write-off in the fourth quarter, consisting of a $15 million pretax impairment and an $8 million pretax provision for revenue refund. The agreement requires $2 million of the provision to be refunded to customers in the first billing cycle following LPSC approval of the settlement and the remaining $8 million to be amortized as a cost of service reduction for customers over 5 years, effective August 1, 2018. In February 2018, the LPSC approved the settlement agreement.

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which was effective August 2015. In February 2018, LPSC staff filed a report approving the increase as filed. This increase is subject to refund pending commission approval . If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Louisiana Formula Rate Filing

In April 2017, the LPSC approved an uncontested stipulation agreement that SWEPCo filed for its formula rate plan for test year 2015. The filing included a net annual increase not to exceed $31 million, which was effective May 2017 and includes SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls which were placed in service in 2016. The net annual increase is subject to refund. In October 2017, SWEPCo filed testimony in Louisiana supporting the prudence of its environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants. These environmental costs are subject to prudence review. A hearing at the LPSC is scheduled for May 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 total approximately $850 million, excluding AFUDC. As of December 31, 2017, SWEPCo had incurred costs of $398 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of December 31, 2017, the total net book value of Welsh Plant, Units 1 and 3 was $627 million, before cost of removal, including materials and supplies inventory and CWIP.

In 2016, as approved by the APSC, SWEPCo began recovering $79 million related to the Arkansas jurisdictional share of these environmental costs, subject to prudence review in the next Arkansas filed base rate proceeding. In April 2017, the LPSC approved recovery of $131 million in investments related to its Louisiana jurisdictional share of environmental controls installed at Welsh Plant, effective May 2017. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $11 million, excluding $6 million of unrecognized equity as of December 31, 2017, (b) is subject to review by the LPSC, and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. In January 2018, SWEPCo received written approval from the PUCT to recover its project costs from retail customers in its 2016 Texas base rate case and is recovering these costs from wholesale customers through SWEPCo's FERC-approved agreements. See "2016 Texas Base Rate Case" and "2017 Louisiana Formula Rate Filing" disclosures above.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

<u>FERC Rate Matters</u>

PJM Transmission Rates **(Applies to AEP, AEPTCo, APCo, I&M and OPCo)**

In June 2016, PJM transmission owners, including AEP's eastern transmission subsidiaries and various state commissions filed a settlement agreement at the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In July 2016, certain parties filed comments at the FERC contesting the settlement agreement. Upon final FERC approval, PJM would implement a transmission enhancement charge adjustment through the PJM OATT, billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms.

FERC Transmission Complaint - AEP's PJM Participants **(Applies to AEP, AEPTCo, APCo, I&M and OPCo)**

In October 2016, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's eastern transmission subsidiaries in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's PJM Transmission Rates **(Applies to AEP, AEPTCo, APCo, I&M and OPCo)**

In November 2016, AEP's eastern transmission subsidiaries filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, AEP's eastern transmission subsidiaries filed an uncontested settlement agreement with the FERC resolving all outstanding issues. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's SPP Participants **(Applies to AEP, AEPTCo, PSO and SWEPCo)**

In June 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's western transmission subsidiaries in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's SPP Transmission Rates **(Applies to AEP, AEPTCo, PSO and SWEPCo)**

In October 2017, AEP's western transmission subsidiaries filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected 2018 calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC SWEPCo Power Supply Agreements Complaint - East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC)

In September 2017, ETEC and NTEC filed a complaint at the FERC that states the base return on common equity used by SWEPCo in calculating their power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining
	2017	2016	Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 203.1	$ 61.4	1 year
Under-recovered Fuel Costs - does not earn a return	89.4	95.2	1 year
Total Current Regulatory Assets	$ 292.5	$ 156.6	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 50.3	$ 159.9	
Ohio Capacity Deferral	—	96.7	
Storm-Related Costs	—	25.1	
Other Regulatory Assets Pending Final Regulatory Approval	9.6	10.4	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	128.0	25.9	
Plant Retirement Costs - Asset Retirement Obligation Costs	39.7	29.6	
Cook Plant Uprate Project	36.3	36.3	
Environmental Control Projects	—	24.1	
Cook Plant Turbine	15.9	12.8	
Other Regulatory Assets Pending Final Regulatory Approval	42.2	29.3	
Total Regulatory Assets Pending Final Regulatory Approval (b)	322.0	450.1	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (c)	682.6	550.6	27 years
Ohio Capacity Deferral	172.6	201.9	2 years
Basic Transmission Cost Rider	90.8	19.9	2 years
Meter Replacement Costs	83.7	99.9	10 years
Ohio Distribution Decoupling	61.7	41.8	2 years
Storm-Related Costs	39.3	15.3	4 years
Plant Retirement Costs - Asset Retirement Obligation Costs	34.3	18.3	23 years
Advanced Metering System	33.5	20.9	3 years
Environmental Control Projects	28.1	—	23 years
Mitchell Plant Transfer	17.8	18.5	23 years

West Virginia Delayed Customer Billing	8.4	19.5	1 year
Ohio Phase-In Recovery Rider	—	218.9	
Other Regulatory Assets Approved for Recovery	41.0	55.4	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,196.3	1,516.2	12 years
Unrealized Loss on Forward Commitments	139.3	119.1	15 years
Unamortized Loss on Reacquired Debt	129.9	137.8	28 years
Cook Plant Nuclear Refueling Outage Levelization	66.7	75.2	2 years
Deferred PJM Fees	48.0	—	2 years
Storm-Related Costs	44.2	58.7	6 years
Peak Demand Reduction/Energy Efficiency	40.1	49.9	3 years
Postemployment Benefits	39.1	39.1	5 years
Plant Retirement Costs - Asset Retirement Obligation Costs	37.2	48.9	23 years
Vegetation Management	33.5	31.4	7 years
Virginia Transmission Rate Adjustment Clause	32.6	38.7	2 years

Medicare Subsidy	32.5	37.2	7 years
Off-system Sales Margin Sharing - Indiana	9.0	24.3	2 years
United Mine Workers of America Pension Withdrawal	0.5	20.2	5 years
Income Taxes, Net	—	1,575.0	
OVEC Purchased Power	—	22.1	
Other Regulatory Assets Approved for Recovery	122.9	100.7	various
Total Regulatory Assets Approved for Recovery	3,265.6	5,175.4	
Total Noncurrent Regulatory Assets	$ 3,587.6	$ 5,625.5	

(a) As of December 31, 2017, AEP Texas has deferred $100 million related to Hurricane Harvey and is currently exploring recovery options.

(b) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015 primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. Recovery of the remaining Virginia net book value for the retired plants will be considered in APCo's next depreciation study. The Virginia SCC staff has requested that the company prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018.

(c) In March 2017, $41 million was reclassified from accumulated depreciation to regulatory assets related to Northeastern Plant, Unit 3. As of December 31, 2017 the unrecovered plant balance related to Northeastern Plant, Unit 3 was $57 million.

	AEP		
	December 31,		Remaining
	2017	2016	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 8.7	$ 3.8	1 year
Over-recovered Fuel Costs - does not pay a return	3.2	4.2	1 year
Total Current Regulatory Liabilities	$ 11.9	$ 8.0	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			

	2017	2016	Remaining Refund Period
Income Taxes, Net (a)	$ 4,412.8	$ —	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.8	
Total Regulatory Liabilities Pending Final Regulatory Determination	4,413.0	0.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs (b)	2,637.1	2,627.5	(c)
Advanced Metering Infrastructure Surcharge	12.7	17.0	3 years
Deferred Investment Tax Credits	10.6	12.6	41 years
Excess Earnings	9.4	10.0	36 years
Louisiana Refundable Construction Financing Costs	—	16.2	
Other Regulatory Liabilities Approved for Payment	1.3	1.6	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	945.0	731.2	(d)
Deferred Investment Tax Credits	191.2	132.9	45 years
Transition Charges	46.0	40.5	10 years
Spent Nuclear Fuel	43.2	44.2	(d)
Enhanced Service Reliability Plan	30.6	21.7	2 years
Peak Demand Reduction/Energy Efficiency	25.6	34.0	2 years
Other Regulatory Liabilities Approved for Payment	56.6	61.1	various
Total Regulatory Liabilities Approved for Payment	4,009.3	3,750.5	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,422.3	$ 3,751.3	

(a) This balance primarily represents regulatory liabilities for excess accumulated deferred income taxes (Excess ADIT) as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See "Federal Tax Reform" section of Note 12 for additional information.

(b) As of December 31, 2017, I&M also charged $43 million to asset removal costs related to various Tanners Creek Plant related assets, primarily related to the net book value of ARO assets. The Indiana and Michigan retail jurisdictions of I&M have increased depreciation rates on Rockport Plant to recover the net book value of Tanners Creek Plant that was retired in 2015. I&M intends to address the need for increases in depreciation rates to recover the deferral in its next Indiana and Michigan base rate cases.
(c) Relieved as removal costs are incurred.
(d) Relieved when plant is decommissioned.

	AEP Texas		
	December 31,		Remaining Recovery Period
Regulatory Assets:	2017	2016	
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Storm-Related Costs	$ —	$ 25.1	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	123.3	—	

Rate Case Expense	0.1	0.1	
Total Regulatory Assets Pending Final Regulatory Approval	123.4	25.2	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	44.9	49.8	10 years
Advanced Metering System	33.5	21.3	3 years
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	151.2	188.2	12 years
Transmission Cost Recovery Factor	9.5	5.3	1 year
Unamortized Loss on Reacquired Debt	7.7	7.3	20 years
Income Taxes, Net	—	40.3	
Other Regulatory Assets Approved for Recovery	8.5	9.8	various
Total Regulatory Assets Approved for Recovery	255.3	322.0	
Total Noncurrent Regulatory Assets	$ 378.7	$ 347.2	

(a) As of December 31, 2017, AEP Texas has deferred $100 million related to Hurricane Harvey and is currently exploring recovery options.

	AEP Texas		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	**2017**	**2016**	
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 642.9	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	642.9	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	599.2	581.7	(b)
Advanced Metering Infrastructure Surcharge	12.7	17.0	3 years
Excess Earnings	6.8	7.3	14 years
Regulatory Liabilities Currently Not Paying a Return			
Transition Charges	46.0	40.5	10 years
Deferred Investment Tax Credits	12.3	13.9	45 years
Other Regulatory Liabilities Approved for Payment	0.6	0.4	various
Total Regulatory Liabilities Approved for Payment	677.6	660.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,320.5	$ 660.8	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.

	AEPTCo		
	December 31,		Remaining Recovery Period
Regulatory Assets:	**2017**	**2016**	
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Income Taxes, Net	$ —	$ 106.1	
Under-Recovered SPP Revenues	—	1.6	
Regulatory Assets Currently Not Earning a Return			
Under-Recovered OATT Costs	11.7	4.6	1 year
Total Regulatory Assets Approved for Recovery	11.7	112.3	
Total Noncurrent Regulatory Assets	$ 11.7	$ 112.3	

	AEPTCo		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	**2017**	**2016**	
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 427.0	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	427.0	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	66.7	44.0	(b)
Total Regulatory Liabilities Approved for Payment	66.7	44.0	
Total Noncurrent Regulatory Liabilities	$ 493.7	$ 44.0	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.

Regulatory Assets:	APCo December 31, 2017	APCo December 31, 2016	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 21.4	$ 6.2	1 year
Under-recovered Fuel Costs - does not earn a return	67.4	62.2	1 year
Total Current Regulatory Assets	$ 88.8	$ 68.4	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ 9.1	$ 9.1	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	39.7	29.6	
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6	
Total Regulatory Assets Pending Final Regulatory Approval (a)	49.4	39.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant - West Virginia	86.3	85.4	26 years
West Virginia Delayed Customer Billing	7.8	18.1	1 year
Other Regulatory Assets Approved for Recovery	3.9	6.8	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	168.8	221.4	12 years
Unamortized Loss on Reacquired Debt	93.2	97.2	28 years
Vegetation Management Program - West Virginia	33.5	31.4	7 years
Virginia Transmission Rate Adjustment Clause	32.6	38.7	2 years
Storm-Related Costs - West Virginia	32.2	47.8	3 years
Postemployment Benefits	18.8	17.4	5 years
Peak Demand Reduction/Energy Efficiency	18.1	19.2	3 years
Virginia Generation Rate Adjustment Clause	7.3	6.5	2 years
Income Taxes, Net	—	463.5	
Other Regulatory Assets Approved for Recovery	22.0	28.4	various
Total Regulatory Assets Approved for Recovery	524.5	1,081.8	
Total Noncurrent Regulatory Assets	$ 573.9	$ 1,121.1	

(a) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015 primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. Recovery of the remaining Virginia net book value for the retired plants will be considered in APCo's next depreciation study. The Virginia SCC staff has requested that the company prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018.

Regulatory Liabilities:	APCo December 31, 2017		APCo December 31, 2016		Remaining Refund Period
	(in millions)				
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits					
Regulatory liabilities pending final regulatory determination:					
Regulatory Liabilities Currently Paying a Return					
Income Taxes, Net (a)	$	820.3	$	—	
Total Regulatory Liabilities Pending Final Regulatory Determination		820.3		—	
Regulatory liabilities approved for payment:					
Regulatory Liabilities Currently Paying a Return					
Asset Removal Costs		615.8		616.9	(b)
Deferred Investment Tax Credits		0.9		0.9	41 years
Regulatory Liabilities Currently Not Paying a Return					
Unrealized Gain on Forward Commitments		9.5		1.3	7 years
Consumer Rate Relief - West Virginia		6.5		5.1	1 year
Other Regulatory Liabilities Approved for Payment		1.9		3.6	various
Total Regulatory Liabilities Approved for Payment		634.6		627.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$	1,454.9	$	627.8	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See “Federal Tax Reform” section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

Regulatory Assets:	I&M December 31, 2017		I&M December 31, 2016		Remaining Recovery Period
	(in millions)				
Current Regulatory Assets					
Under-recovered Fuel Costs - earns a return	$	15.0	$	13.0	1 year
Under-recovered Fuel Costs - does not earn a return		—		13.1	
Total Current Regulatory Assets	$	15.0	$	26.1	
Noncurrent Regulatory Assets					
Regulatory assets pending final regulatory approval:					
Regulatory Assets Currently Not Earning a Return					
Cook Plant Uprate Project	$	36.3	$	36.3	

Cook Plant Turbine	15.9	12.8	
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	14.7	8.1	
Rockport Plant Dry Sorbent Injection System - Indiana	10.4	6.6	
Other Regulatory Assets Pending Final Regulatory Approval	2.0	0.9	
Total Regulatory Assets Pending Final Regulatory Approval	79.3	64.7	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	245.3	252.8	27 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	6.0	6.3	21 years
Other Regulatory Assets Approved for Recovery	1.0	2.5	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	77.8	141.9	12 years
Cook Plant Nuclear Refueling Outage Levelization	66.7	75.2	2 years
Deferred PJM Fees	48.0	—	2 years
Postemployment Benefits	9.7	11.4	5 years
Unamortized Loss on Reacquired Debt	9.5	10.7	15 years
Off-system Sales Margin Sharing - Indiana	9.0	24.3	2 years
Medicare Subsidy	7.1	8.2	7 years
Income Taxes, Net	—	302.6	
Other Regulatory Assets Approved for Recovery	20.0	16.0	various
Total Regulatory Assets Approved for Recovery	500.1	851.9	
Total Noncurrent Regulatory Assets	$ 579.4	$ 916.6	

	I&M		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	2017	2016	
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ 2.7	$ —	1 year
Total Current Regulatory Liabilities	$ 2.7	$ —	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 472.7	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	472.7	—	
Regulatory liabilities approved for payment:			

Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs (b)	202.2	236.5	(c)
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	945.0	731.2	(d)
Spent Nuclear Fuel	43.2	44.2	(d)
Deferred Investment Tax Credits	34.1	38.8	20 years
Other Regulatory Liabilities Approved for Payment	11.5	14.8	various
Total Regulatory Liabilities Approved for Payment	1,236.0	1,065.5	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,708.7	$ 1,065.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See "Federal Tax Reform" section of Note 12 for additional information.

(b) As of December 31, 2017, I&M has charged $43 million to asset removal costs related to various Tanners Creek Plant related assets, primarily related to the net book value of ARO assets. The Indiana and Michigan retail jurisdictions of I&M have increased depreciation rates on Rockport Plant to recover the net book value of Tanners Creek Plant that was retired in 2015. I&M intends to address the need for increases in depreciation rates to recover the deferral in its next Indiana and Michigan base rate cases.

(c) Relieved as removal costs are incurred.

(d) Relieved when plant is decommissioned.

	OPCo		
	December 31,		Remaining Recovery Period
Regulatory Assets:	2017	2016	
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 115.9	$ —	1 year
Total Current Regulatory Assets	$ 115.9	$ —	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Capacity Deferral	$ —	$ 96.7	(b)
Regulatory Assets Currently Not Earning a Return			
Smart Grid Costs	—	4.1	
Total Regulatory Assets Pending Final Regulatory Approval	—	100.8	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Capacity Deferral	172.6	201.9	2 years
Basic Transmission Cost Rider	90.8	19.9	2 years
Distribution Decoupling	61.7	41.8	2 years
Phase-In Recovery Rider	—	218.9	
Other Regulatory Assets Approved for Recovery	1.7	4.2	various
Regulatory Assets Currently Not Earning a Return			

Pension and OPEB Funded Status	170.6	225.2	12 years
Unrealized Loss on Forward Commitments	131.8	118.6	15 years
Unamortized Loss on Reacquired Debt	7.8	9.1	21 years
Income Taxes, Net	—	126.4	
OVEC Purchased Power	—	22.1	
Other Regulatory Assets Approved for Recovery	15.8	18.6	various
Total Regulatory Assets Approved for Recovery	652.8	1,006.7	
Total Noncurrent Regulatory Assets	$ 652.8	$ 1,107.5	

(a) December 31, 2017 balance includes Phase-In Recovery Rider.
(b) Capacity Deferral related to 2016 Global Settlement was approved for recovery effective March 2017.

	OPCo		
	December 31,		Remaining Refund Period
	2017	2016	
Regulatory Liabilities:	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ —	$ 4.2	
Total Current Regulatory Liabilities	$ —	$ 4.2	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 604.2	$ —	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	604.4	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	428.8	432.4	(b)
Other Regulatory Liabilities Approved for Payment	1.4	0.3	various
Regulatory Liabilities Currently Not Paying a Return			
Enhanced Service Reliability Plan	30.6	21.7	2 years
Peak Demand Reduction/Energy Efficiency	23.6	29.0	2 years
Smart Grid Costs	1.4	11.9	1 year
Other Regulatory Liabilities Approved for Payment	10.0	10.7	various
Total Regulatory Liabilities Approved for Payment	495.8	506.0	

Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,100.2	$ 506.2

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See "Federal Tax Reform" section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

	PSO		
	December 31,		Remaining Recovery Period
	2017	2016	
Regulatory Assets:	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 36.7	$ 33.8	1 year
Total Current Regulatory Assets	$ 36.7	$ 33.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ —	$ 84.5	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.5	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	3.2	20.0	
Environmental Control Projects	—	13.1	
Other Regulatory Assets Pending Final Regulatory Approval	0.1	—	
Total Regulatory Assets Pending Final Regulatory Approval	3.3	118.1	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (a)	138.5	—	23 years
Storm-Related Costs	39.0	10.8	4 years
Meter Replacement Costs	38.8	50.1	7 years
Environmental Control Projects	28.1	—	23 years
Red Rock Generating Facility	8.8	9.1	39 years
Other Regulatory Assets Approved for Recovery	0.5	—	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	72.7	98.1	12 years
SPP Base Plan Fees	16.3	10.7	2 years
Peak Demand Reduction/Energy Efficiency	13.0	10.3	2 years
Unamortized Loss on Reacquired Debt	5.0	5.8	15 years
Deferred System Reliability Rider Expenses	—	12.5	
Income Taxes, Net	—	9.3	
Other Regulatory Assets Approved for Recovery	4.1	5.4	various

Total Regulatory Assets Approved for Recovery	364.8	222.1	
Total Noncurrent Regulatory Assets	$ 368.1	$ 340.2	

(a) In March 2017, $41 million was reclassified from accumulated depreciation to regulatory assets related to Northeastern Plant, Unit 3. As of December 31, 2017 the unrecovered plant balance related to Northeastern Plant, Unit 3 was $57 million.

	PSO		
	December 31,		Remaining Refund Period
	2017	2016	
Regulatory Liabilities:	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 531.7	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	531.7	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	268.8	279.3	(b)
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	50.7	48.0	41 years
Advanced Metering Costs	0.6	11.5	1 year
Other Regulatory Liabilities Approved for Payment	1.7	0.9	various
Total Regulatory Liabilities Approved for Payment	321.8	339.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 853.5	$ 339.7	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See “Federal Tax Reform” section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.

	SWEPCo		
	December 31,		Remaining Recovery Period
	2017	2016	
Regulatory Assets:	(in millions)		

Current Regulatory Assets				
Under-recovered Fuel Costs - earns a return	$ 14.1	$ 8.4	1 year
Total Current Regulatory Assets	$ 14.1	$ 8.4	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 50.3	$ 75.4	
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.8	
Regulatory Assets Currently Not Earning a Return			
Rate Case Expense - Texas	4.3	1.0	
Asset Retirement Obligation - Arkansas, Louisiana	4.0	2.7	
Shipe Road Transmission Project - FERC	3.3	3.1	
Environmental Controls Projects	—	11.0	
Other Regulatory Assets Pending Final Regulatory Approval	2.5	1.9	
Total Regulatory Assets Pending Final Regulatory Approval	64.9	95.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Approved for Recovery	7.2	1.3	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	101.0	119.8	12 years
Plant Retirement Costs - Unrecovered Plant	17.6	—	24 years
Environmental Controls Projects	15.3	—	15 years
Unamortized Loss on Reacquired Debt	4.7	5.4	26 years
Medicare Subsidy	3.7	4.3	7 years
Income Taxes, Net	—	314.2	
Other Regulatory Assets Approved for Recovery	6.2	10.3	various
Total Regulatory Assets Approved for Recovery	155.7	455.3	
Total Noncurrent Regulatory Assets	$ 220.6	$ 551.2	

	SWEPCo		
	December 31,		**Remaining Refund Period**
	2017	**2016**	
Regulatory Liabilities:	**(in millions)**		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ 8.7	$ 3.8	1 year
Total Current Regulatory Liabilities	$ 8.7	$ 3.8	
Noncurrent Regulatory Liabilities and			

Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 455.9	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	455.9	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	424.5	409.7	(b)
Refundable Construction Financing Costs - Louisiana	—	16.2	
Other Regulatory Liabilities Approved for Payment	2.6	3.9	various
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	5.9	7.3	14 years
Other Regulatory Liabilities Approved for Payment	7.5	1.8	various
Total Regulatory Liabilities Approved for Payment	440.5	438.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 896.4	$ 438.9	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. The mechanism and refund period to provide the Excess ADIT to customers will be based on future orders from the respective commission in each jurisdiction. See “Federal Tax Reform” section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

The AEP System has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for “Commitments”, the following tables summarize the Registrants’ actual contractual commitments as of December 31, 2017:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,067.6	$ 1,019.5	$ 544.9	$ 221.6	$ 2,853.6
Energy and Capacity Purchase Contracts	230.1	456.1	378.0	1,467.3	2,531.5
Total	$ 1,297.7	$ 1,475.6	$ 922.9	$ 1,688.9	$ 5,385.1

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 369.1	$ 364.4	$ 165.2	$ 0.9	$ 899.6
Energy and Capacity Purchase Contracts	36.0	72.3	72.9	354.9	536.1
Total	$ 405.1	$ 436.7	$ 238.1	$ 355.8	$ 1,435.7

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 236.9	$ 269.4	$ 204.6	$ 166.6	$ 877.5
Energy and Capacity Purchase Contracts	125.4	255.9	259.9	352.4	993.6
Total	$ 362.3	$ 525.3	$ 464.5	$ 519.0	$ 1,871.1

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 29.9	$ 59.3	$ 58.4	$ 363.7	$ 511.3

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 45.9	$ 71.7	$ 30.5	$ —	$ 148.1
Energy and Capacity Purchase Contracts	91.5	181.5	127.8	236.8	637.6
Total	$ 137.4	$ 253.2	$ 158.3	$ 236.8	$ 785.7

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 111.7	$ 85.8	$ 55.4	$ —	$ 252.9
Energy and Capacity Purchase Contracts	33.0	67.3	53.4	151.0	304.7
Total	$ 144.7	$ 153.1	$ 108.8	$ 151.0	$ 557.6

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

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

Letters of Credit (Applies to AEP, AEP Texas and OPCo)

Standby letters of credit are entered into with third parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has a $3 billion revolving credit facility due in June 2021, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2017, no letters of credit were issued under the $3 billion revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP also issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $345 million. In October 2017, a $100 million uncommitted facility expired. As of December 31, 2017, the Registrants' maximum future payments for letters of credit issued under the uncommitted facilities were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 103.5	January 2018 to December 2018
AEP Texas	2.8	January 2018
OPCo	0.6	September 2018

AEP has $45 million of variable rate Pollution Control Bonds supported by $46 million of bilateral letters of credit maturing in July 2019.

Guarantees of Third-Party Obligations (Applies to AEP and SWEPCo)

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. It is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $76 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of December 31, 2017, SWEPCo has collected approximately $72 million through a rider for final mine closure and reclamation costs, of which $76 million is recorded in Asset Retirement Obligations, offset by $4 million that is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheet.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Guarantees of Equity Method Investees (Applies to AEP)

AEP issued a performance guarantee for a 50% owned joint venture which is accounted for as an equity method investment. If the joint venture were to default on payments or performance, AEP would be required to make payments on behalf of the joint venture. As of December 31, 2017, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2017, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase and sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf. AEPSC also conducts power purchase and sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

Certain Registrants lease certain equipment under master lease agreements. See "Master Lease Agreements", "Railcar Lease" and "AEPRO Boat and Barge Leases" sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2017, APCo and OPCo are named as a Potentially Responsible Party (PRP) for one site and three sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are eleven additional sites for which APCo, I&M, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at two sites under state law including the I&M site discussed in the next paragraph. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of completed remediation work in 2015 and 2017, I&M's accrual was reduced. As of December 31, 2017, I&M's accrual for all of these sites is $100 thousand. The remediation work is expected to be completed in 2018.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified

Superfund sites.

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

I&M owns and operates the two-unit 2,278 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. It intends to reorganize, not cease business operations. However, it is in the early stages of the bankruptcy process and it is unclear whether the company can successfully reorganize. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. Westinghouse has stated that it intends to continue performance on I&M’s contracts, but given the importance of upcoming dates in the fuel fabrication process for Cook Plant, and their vital part in Cook Plant’s ongoing operations, I&M continues to work with Westinghouse in the bankruptcy proceedings to avoid any interruptions to that service.

In January 2018, Westinghouse issued a news release stating that it intends to sell all of its global business, including the portion of the nuclear business that contracts with Cook Plant. Any sale would require approval by the bankruptcy court. In the unlikely event Westinghouse rejects I&M’s contracts, or there is an interference with the sale process, Cook Plant’s operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2015. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste is $1.6 billion in 2015 nondiscounted dollars, with additional ongoing costs of $5 million per year for post decommissioning storage of SNF and an eventual cost of $57 million for the subsequent decommissioning of the spent fuel storage facility, also in 2015 nondiscounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $9 million, $9 million and $9 million for the years ended December 31, 2017, 2016 and 2015, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2017 and 2016, the total decommissioning trust fund balance was $2.2 billion and $1.9 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the Department of Energy (DOE) through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to zero. As of December 31, 2017 and 2016, fees and related interest of $269 million and $266 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $312 million and $311 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $22 million, $6 million and $13 million in 2017, 2016 and 2015, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December 31, 2017, I&M has deferred $11 million in Prepayments and Other Current Assets and $5 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Insurance

I&M carries insurance coverage in the amount of $3 billion for a nuclear incident at the Cook Plant for decontamination, stabilization and extraordinary incidents caused by premature decommissioning. Insurance coverage for a nonnuclear property incident at the Cook Plant is $1.5 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $51 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident at $13.4 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $450 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $127 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $255 million per nuclear incident payable in annual installments of $38 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $450 million through commercially available insurance. The next level of liability coverage of up to $13 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

The Registrants maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. The

Registrants also maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by the Registrants. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of I&M's nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation (Applies to AEP and I&M)

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 plaintiffs further allege that the defendants' actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. 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 plaintiffs' claims, including the dismissal without prejudice of plaintiffs' claims seeking compensatory damages. 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 plaintiffs 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 plaintiffs' 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 an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether AEGCo and I&M are in breach of certain contract provisions that plaintiffs allege operate to protect the plaintiffs' residual interests in the unit and whether the trial court erred in dismissing plaintiffs' claims that AEGCo and I&M breached the covenant of good faith and fair dealing.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court's decisions which had dismissed certain of plaintiffs' claims for breach of contract and remanding the case to the district court to enter summary judgment in plaintiffs' favor consistent with that ruling. In April 2017, AEGCo and I&M filed a petition for rehearing with the U.S. Court of Appeals for the Sixth Circuit, which was granted. In June 2017, the U.S. Court of Appeals for the Sixth Circuit issued an amended opinion and judgment which reverses the district court's dismissal of certain of the owners' claims under the lease agreements, vacates the denial of the owners' motion for partial summary judgment and remands the case to the district court for further proceedings. The amended opinion and judgment also affirms the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removes the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management is unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits (Applies to AEP)

In 2002, a lawsuit was commenced in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP is among the companies named as defendants in some of these cases. AEP has settled, received summary judgment or was dismissed from all of these cases in 2017.

Gavin Landfill Litigation (Applies to AEP and OPCo)

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill. As a result of OPCo transferring its generation assets to AGR, the outcome of this complaint will be the responsibility of AGR. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors. Twelve of the family members are pursuing personal injury/illness claims (non-working direct claims) and the remainder are pursuing loss of consortium claims. The plaintiffs seek compensatory and punitive damages, as well as medical monitoring. In September 2014, defendants filed a motion to dismiss the complaint, contending the case should be filed in Ohio. In August 2015, the court denied the motion. Defendants appealed that decision to the West Virginia Supreme Court. In February 2016, a decision was issued by the court denying the appeal and remanding the case to the West Virginia Mass Litigation Panel (WVMLP), rather than back to the Mason County, West Virginia Circuit Court. Defendants subsequently filed a motion to dismiss the twelve non-working direct claims under Ohio law. The WVMLP denied the motion and defendants again appealed to the West Virginia Supreme Court. In June 2017, the West Virginia Supreme Court reversed the WVMLP decision and dismissed the claims of the twelve non-working direct claim plaintiffs. Management will continue to defend against the remaining claims and believes the provision recorded is adequate. Management is unable to determine a range of potential additional losses that are reasonably possible of occurring.

7. DISPOSITIONS, ASSETS AND LIABILITIES HELD FOR SALE AND IMPAIRMENTS

The disclosures in this note apply to AEP unless indicated otherwise.

DISPOSITIONS

2017

Zimmer Plant (Generation & Marketing Segment)

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to a nonaffiliated party. The transaction closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition. The Income before Income Tax Expense and Equity Earnings of Zimmer Plant was immaterial for the years ended December 31, 2017, 2016, and 2015.

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby Plants as well as AEGCo's Lawrenceburg Plant totaling 5,329 MWs of competitive generation assets to a nonaffiliated party. The sale closed in January 2017 for $2.2 billion, which was recorded in Investing Activities on the statement of cash flows. The net proceeds from the transaction were $1.2 billion in cash after taxes, repayment of debt associated with these assets including a make whole payment related to the debt, payment of a coal contract associated with one of the plants and transaction fees. The sale resulted in a pretax gain of $226 million that was recorded in Gain on Sale of Merchant Generation Assets on AEP's statement of income for the year ended December 31, 2017.

2016

Tanners Creek Plant (Vertically Integrated Utilities Segment) (Applies to AEP and I&M)

In October 2016, I&M sold its retired Tanners Creek Plant site including its associated asset retirement obligations (AROs) to a nonaffiliated party. I&M paid $92 million and the nonaffiliated party took ownership of the Tanners Creek plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. I&M did not record a gain or loss related to this sale and will address recovery of Tanners Creek deferred costs in future rate proceedings. If any of the costs associated with Tanners Creek are not recoverable, it could reduce future net income and impact financial condition.

Wind Farms (Applies to AEP Texas)

In December 2016, TCC and TNC merged into AEP Utilities, Inc. Prior to the merger, AEP Utilities, Inc. was a subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. CSW Energy, Inc. owns the Desert Sky and Trent Wind Farms ("Wind Farms"). Upon merger, AEP Utilities, Inc. changed its name to AEP Texas. Subsequent to the merger, AEP Texas exited the merchant generation business by transferring all of the common stock of the Wind Farms to a competitive AEP affiliate. No gain or loss was recognized and no cash was exchanged related to the disposition of the Wind Farms.

In the fourth quarter of 2016, the Wind Farms were determined to be discontinued operations. Accordingly, results of operations of the Wind Farms have been classified as discontinued operations on AEP Texas' statements of income for the years ended December 31, 2016 and 2015 as shown in the following table:

AEP Texas

	Years Ended December 31, 2016	2015
	(in millions)	
Revenue	$ 18.2	$ 22.4

Other Operation Expense	6.5	6.5
Maintenance Expense	3.4	4.9
Asset Impairment and Other Related Charges	72.7	—
Depreciation and Amortization Expense	9.8	11.5
Taxes Other Than Income Taxes	1.3	1.3
Total Expenses	93.7	24.2
Other Income (Expense)	(0.8)	(1.3)
Pretax Income of Discontinued Operations	(76.3)	(3.1)
Income Tax Expense	(27.5)	(1.7)
Total Income on Discontinued Operations as Presented on the Statements of Income	$ (48.8)	$ (1.4)

2015

Muskingum River Plant (Generation & Marketing Segment)

In August 2015, AGR sold its retired Muskingum River Plant site including its associated asset retirement obligations to a nonaffiliated party. AGR paid $48 million and the nonaffiliated party took ownership of the Muskingum River Plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. As a result of the sale, a net gain of $32 million was recognized and recorded in Other Operation on the statements of income. The cash paid was recorded in Operating Activities on the statements of cash flows.

AEPRO (Corporate and Other)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. The nonaffiliated party acquired AEPRO by purchasing all of the common stock of AEP Resources, Inc., the parent company of AEPRO. The nonaffiliated party assumed certain assets and liabilities of AEPRO, excluding the equity method investment in International Marine Terminals, LLC, pension and benefit assets and liabilities and debt obligations. Prior to the closing of the sale, AEP retired the debt obligations of AEPRO. AEP retained ownership of its captive barge fleet that delivers coal to the company's regulated coal-fueled power plant units owned or leased by AEGCo, APCo, I&M, KPCo and WPCo. AEP signed a contract with the nonaffiliated party to dispatch and schedule its captive barge fleet for the company's regulated coal-fueled power plant units. AEP also had a separate contract with the nonaffiliated party to barge coal for AGR. These agreements with the nonaffiliated party extend through the end of 2019.

Results of operations of AEPRO have been classified as discontinued operations on AEP's statement of income for the year ended December 31, 2015, as shown in the following table:

Corporate and Other

	Years Ended December 31, 2015
	(in millions)
Other Revenues	$ 447.1

Other Operation Expense		321.3
Maintenance Expense		21.5
Depreciation and Amortization Expense		26.9
Taxes Other Than Income Taxes		10.6
Total Expenses		380.3
Other Income (Expense)		(16.9)
Pretax Income of Discontinued Operations		49.9
Income Tax Expense		19.4
Equity Earnings of Unconsolidated Subsidiaries		(0.1)
Income from Discontinued Operations of AEPRO		30.4
Gain on Sale of Discontinued Operations		240.1
Income Tax Expense (Benefit)		(13.2)
Gain on Sale of Discontinued Operations, Net of Tax		253.3
Total Income on Discontinued Operations as Presented on the Statement of Income	$	283.7

In the second quarter of 2016, AEP recorded a $3 million loss related to the final accounting for the sale of AEPRO, which was recorded in Income (Loss) from Discontinued Operations, Net of Tax, on AEP's statements of income.

ASSETS AND LIABILITIES HELD FOR SALE

2016

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In the third quarter of 2016, management determined the Gavin, Waterford, Darby and Lawrenceburg Plants met the classification of held for sale. Accordingly, the four plants' assets and liabilities were recorded as Assets Held for Sale and Liabilities Held for Sale on AEP's balance sheet as of December 31, 2016 and as shown in the table below. The Income before Income Tax Expense and Equity Earnings of the four plants was approximately $375 million and $451 million for the years ended December 31, 2016 and 2015, respectively.

Generation & Marketing Segment

	December 31, 2016	
Assets:	(in millions)	
Fuel	$	145.5
Materials and Supplies		49.4
Property, Plant and Equipment - Net		1,756.2
Other Class of Assets That Are Not Major		0.1
Total Assets Classified as Held for Sale on the Balance Sheet	$	1,951.2
Liabilities:		

Long-term Debt	$	134.8
Waterford Plant Upgrade Liability		52.2
Asset Retirement Obligations		36.7
Other Classes of Liabilities That Are Not Major		12.2
Total Liabilities Classified as Held for Sale on the Balance Sheet	$	235.9

IMPAIRMENTS

2017

Merchant Generating Assets (Generation & Marketing Segment)

Through the third quarter of 2017, AEP recorded an additional pretax impairment of $4 million in Asset Impairments and Other Related Charges on AEP's statements of income related to the Merchant Coal-fired Generation Assets. The initial impairment recorded related to these assets is discussed in the "2016" section below. In addition, AEP recorded a $7 million pretax impairment as Asset Impairments and Other Related Charges on AEP's statements of income related to the sale of Zimmer Plant. The sale is further discussed in the "Disposition" section of this note.

Due to a significant increase in estimated costs identified in December 2017 to repair a defective dam structure at Racine Hydroelectric Plant ("Racine"), AEP performed an impairment analysis on Racine in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a fair value determination for Racine of $0 and AEP recorded a pretax impairment of $43 million in Assets Impairments and Other Related Charges on the statement of income in the fourth quarter of 2017.

Welsh Plant, Unit 2 and Turk Plant (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)

In December 2017, SWEPCo recorded a pretax impairment of $19 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional share of Welsh Plant, Unit 2 and other disallowed plant investments. Additionally in December 2017, SWEPCo recorded a pretax impairment of $15 million in Asset Impairments and Other Related Charges on the statements of income related to the Louisiana jurisdictional share of the Turk Plant. See the "2016 Texas Base Rate Case" and "Louisiana Turk Plant Prudence Review" sections of Note 4.

2016

Merchant Generating Assets (Generation & Marketing Segment)

In September 2016, due to AEP's ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP's existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. Cardinal, Unit 1, a 43.5% interest in Conesville, Unit 4, Conesville, Units 5 and 6, a 26% interest in Stuart, Units 1-4, a 25.4% interest in Zimmer, Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets") were subject to this analysis. Additionally, Racine, Putnam and I&M's Price River coal reserves ("Coal Reserves") and the Wind Farms were also included in this analysis. For the Merchant Coal-Fired Generation Assets, Racine and the Wind Farms, AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful lives of the assets based upon energy and capacity price curves, as applicable, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step one analysis concluded the book value of

Racine would be recovered and the book value of the remaining assets would not be recovered.

AEP performed step two of the impairment analysis on the Merchant Coal-Fired Generation Assets using a ten-year discounted cash flow model based upon forecasted energy and capacity price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step two analysis resulted in projected negative cash flows. Based on this result, coupled with the significant capital investments necessary to comply with environmental rules to allow the Merchant Coal-Fired Generation Assets to operate to the end of their currently estimated depreciable lives and the joint-ownership structure of these facilities, management determined the fair value of these assets was $0. AEP performed step two of the impairment analysis on the Wind Farms using a ten-year discounted cash flow model utilizing forecasted energy price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The results concluded the Wind Farms were also impaired.

For the Coal Reserves, AEP performed step one of the impairment analysis and concluded the book value of the assets would not be recovered. Step two of the impairment analysis on the Coal Reserves was performed using a market approach with Level 3 unobservable inputs. The results concluded the Coal Reserves were also impaired.

Based on the impairment analysis performed, in the third quarter of 2016, AEP recorded a pretax impairment of $2.3 billion in Asset Impairments and Other Related Charges on the statements of income. See the table below for additional information.

Impaired Assets	Book Value	Fair Value	Impairment
		(in millions)	
Merchant Coal-Fired Generation Assets	$ 2,139.4	$ —	$ 2,139.4
Trent and Desert Sky Wind Farms	118.7	46.0	72.7
Coal Reserves (a)	56.6	3.8	52.8
Total	$ 2,314.7	$ 49.8	$ 2,264.9

(a) Includes the $11 million book value of I&M's Price River Coal Reserves which were fully impaired. This $11 million impairment is reflected in the Vertically Integrated Utilities Segment.

Based on capital expenditure activity of the Merchant Coal-fired Generation Assets in the fourth quarter of 2016, AEP recorded a pretax impairment of an additional $3 million in Asset Impairments and Other Related Charges on AEP's statement of income.

8. BENEFIT PLANS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees.

Due to the Registrant Subsidiaries' participation in AEP's benefits plans, the assumptions used by the actuary and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrants and the rate of compensation increase for each Registrant.

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. The Registrants recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of the Registrants' benefit obligations are shown in the following tables:

	Pension Plans		OPEB	
	December 31,			
Assumption	**2017**	**2016**	**2017**	**2016**
Discount Rate	3.65%	4.05%	3.60%	4.10%

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	**2017**	**2016**
AEP	4.80%	4.75%
AEP Texas	4.90%	4.85%
APCo	4.60%	4.55%
I&M	4.85%	4.80%
OPCo	4.95%	4.85%
PSO	4.90%	4.90%
SWEPCo	4.80%	4.75%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant.

For 2017, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of each Registrants' benefit costs are shown in the following tables:

Assumptions	Pension Plans 2017	Pension Plans 2016	Pension Plans 2015	OPEB 2017	OPEB 2016	OPEB 2015
	Year Ended December 31,					
Discount Rate	4.05%	4.30%	4.00%	4.10%	4.30%	4.00%
Expected Return on Plan Assets	6.00%	6.00%	6.00%	6.75%	7.00%	6.75%

Assumption – Rate of Compensation Increase (a)	Pension Plans Year Ended December 31, 2017	2016	2015
AEP	4.80%	4.75%	4.80%
AEP Texas	4.90%	4.85%	4.50%
APCo	4.60%	4.55%	4.45%
I&M	4.85%	4.80%	4.80%
OPCo	4.95%	4.85%	4.80%
PSO	4.90%	4.90%	4.80%
SWEPCo	4.80%	4.75%	4.80%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third party forecasts and current prospects for economic growth. The expected return on plan assets is the same for each Registrant.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	December 31, 2017	2016
Initial	6.50%	7.00%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	2024

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost:							
1% Increase	$ 2.5	$ 0.1	$ 0.5	$ 0.2	$ 0.2	$ 0.1	$ 0.1
1% Decrease	(2.0)	(0.1)	(0.4)	(0.2)	(0.2)	(0.1)	(0.1)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation:							
1% Increase	$ 45.4	$ 2.6	$ 10.8	$ 3.7	$ 3.5	$ 1.7	$ 1.9
1% Decrease	(39.6)	(2.4)	(9.1)	(3.4)	(3.2)	(1.5)	(1.8)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2017, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP	**Pension Plans**		**OPEB**	
	2017	**2016**	**2017**	**2016**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 5,085.8	$ 4,992.9	$ 1,447.4	$ 1,450.6
Service Cost	96.5	85.8	11.2	10.2
Interest Cost	203.1	211.6	59.3	60.9
Actuarial (Gain) Loss	182.4	142.7	(97.5)	17.3
Benefit Payments	(352.0)	(347.2)	(128.6)	(130.2)
Participant Contributions	—	—	39.5	37.8
Medicare Subsidy	—	—	0.7	0.8
Benefit Obligation as of December 31,	$ 5,215.8	$ 5,085.8	$ 1,332.0	$ 1,447.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,827.3	$ 4,767.6	$ 1,545.9	$ 1,577.4
Actual Gain on Plan Assets	600.0	315.5	271.6	56.0
Company Contributions	98.8	91.4	4.1	4.9
Participant Contributions	—	—	39.5	37.8
Benefit Payments	(352.0)	(347.2)	(128.6)	(130.2)
Fair Value of Plan Assets as of December 31,	$ 5,174.1	$ 4,827.3	$ 1,732.5	$ 1,545.9
Funded (Underfunded) Status as of December 31,	$ (41.7)	$ (258.5)	$ 400.5	$ 98.5

AEP Texas	**Pension Plans**		**OPEB**	
	2017	**2016**	**2017**	**2016**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 421.7	$ 420.3	$ 120.4	$ 122.0
Transfer of CSW Energy, Inc. Benefit Obligation	—	(2.8)	—	(0.4)
Service Cost	8.6	7.5	0.9	0.7
Interest Cost	17.1	17.8	4.9	5.1

Actuarial (Gain) Loss	25.6	11.1	(11.9)	0.8
Benefit Payments	(31.7)	(32.2)	(10.8)	(11.4)
Participant Contributions	—	—	3.6	3.5
Medicare Subsidy	—	—	—	0.1
Benefit Obligation as of December 31,	$ 441.3	$ 421.7	$ 107.1	$ 120.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 416.6	$ 415.4	$ 134.1	$ 138.6
Transfer of CSW Energy, Inc. Plan Assets	—	(2.5)	—	(0.4)
Actual Gain on Plan Assets	61.8	27.4	20.4	3.8
Company Contributions	9.2	8.5	—	—
Participant Contributions	—	—	3.6	3.5
Benefit Payments	(31.7)	(32.2)	(10.8)	(11.4)
Fair Value of Plan Assets as of December 31,	$ 455.9	$ 416.6	$ 147.3	$ 134.1
Funded (Underfunded) Status as of December 31,	$ 14.6	$ (5.1)	$ 40.2	$ 13.7

APCo	**Pension Plans**		**OPEB**	
	2017	**2016**	**2017**	**2016**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 654.0	$ 653.4	$ 255.6	$ 262.2
Service Cost	9.4	8.1	1.1	1.0
Interest Cost	25.7	27.2	10.6	10.8
Actuarial (Gain) Loss	15.7	9.2	(13.4)	(0.2)
Benefit Payments	(39.8)	(43.9)	(24.3)	(24.8)
Participant Contributions	—	—	6.7	6.4
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 665.0	$ 654.0	$ 236.5	$ 255.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 606.4	$ 603.2	$ 246.9	$ 256.7
Actual Gain on Plan Assets	74.9	38.3	41.6	5.9
Company Contributions	10.2	8.8	2.5	2.7
Participant Contributions	—	—	6.7	6.4
Benefit Payments	(39.8)	(43.9)	(24.3)	(24.8)
Fair Value of Plan Assets as of December 31,	$ 651.7	$ 606.4	$ 273.4	$ 246.9
Funded (Underfunded) Status as of December 31,	$ (13.3)	$ (47.6)	$ 36.9	$ (8.7)

I&M	**Pension Plans**		**OPEB**	
	2017	**2016**	**2017**	**2016**
Change in Benefit Obligation	**(in millions)**			

Benefit Obligation as of January 1,	$ 611.6	$ 591.5	$ 167.6	$ 166.3
Service Cost	14.0	12.2	1.6	1.5
Interest Cost	24.3	25.3	6.9	7.0
Actuarial (Gain) Loss	10.8	20.1	(12.0)	3.8
Benefit Payments	(36.4)	(37.5)	(15.6)	(15.7)
Participant Contributions	—	—	4.9	4.6
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 624.3	$ 611.6	$ 153.5	$ 167.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 586.1	$ 570.0	$ 186.6	$ 189.0
Actual Gain on Plan Assets	74.0	40.6	35.2	8.7
Company Contributions	13.0	13.0	—	—
Participant Contributions	—	—	4.9	4.6
Benefit Payments	(36.4)	(37.5)	(15.6)	(15.7)
Fair Value of Plan Assets as of December 31,	$ 636.7	$ 586.1	$ 211.1	$ 186.6
Funded (Underfunded) Status as of December 31,	$ 12.4	$ (25.5)	$ 57.6	$ 19.0

OPCo	**Pension Plans**		**OPEB**	
	2017	**2016**	**2017**	**2016**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 492.9	$ 497.5	$ 164.0	$ 168.6
Service Cost	7.5	6.5	0.9	0.8
Interest Cost	19.4	20.6	6.7	7.0
Actuarial (Gain) Loss	13.1	4.7	(16.6)	(1.0)
Benefit Payments	(31.8)	(36.4)	(15.5)	(16.2)
Participant Contributions	—	—	4.7	4.7
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 501.1	$ 492.9	$ 144.3	$ 164.0
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 473.8	$ 472.1	$ 182.6	$ 191.6
Actual Gain on Plan Assets	58.9	30.9	26.7	2.5
Company Contributions	8.2	7.2	—	—
Participant Contributions	—	—	4.7	4.7
Benefit Payments	(31.8)	(36.4)	(15.5)	(16.2)
Fair Value of Plan Assets as of December 31,	$ 509.1	$ 473.8	$ 198.5	$ 182.6
Funded (Underfunded) Status as of December 31,	$ 8.0	$ (19.1)	$ 54.2	$ 18.6

PSO	**Pension Plans**		**OPEB**	
	2017	**2016**	**2017**	**2016**

Change in Benefit Obligation		(in millions)		
Benefit Obligation as of January 1,	$ 266.7	$ 265.4	$ 77.6	$ 77.7
Service Cost	6.4	6.2	0.7	0.6
Interest Cost	10.7	11.2	3.2	3.3
Actuarial (Gain) Loss	10.1	3.1	(7.5)	1.0
Benefit Payments	(17.3)	(19.2)	(6.9)	(7.2)
Participant Contributions	—	—	2.3	2.2
Benefit Obligation as of December 31,	$ 276.6	$ 266.7	$ 69.4	$ 77.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 266.0	$ 262.1	$ 86.4	$ 88.3
Actual Gain on Plan Assets	33.6	17.3	13.7	3.1
Company Contributions	5.5	5.8	—	—
Participant Contributions	—	—	2.3	2.2
Benefit Payments	(17.3)	(19.2)	(6.9)	(7.2)
Fair Value of Plan Assets as of December 31,	$ 287.8	$ 266.0	$ 95.5	$ 86.4
Funded (Underfunded) Status as of December 31,	$ 11.2	$ (0.7)	$ 26.1	$ 8.8

SWEPCo	Pension Plans		OPEB	
	2017	2016	2017	2016
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 296.6	$ 282.8	$ 86.9	$ 86.1
Service Cost	8.7	8.1	0.9	0.8
Interest Cost	12.3	12.4	3.6	3.6
Actuarial (Gain) Loss	16.3	13.8	(6.2)	1.5
Benefit Payments	(19.3)	(20.5)	(7.4)	(7.5)
Participant Contributions	—	—	2.5	2.4
Benefit Obligation as of December 31,	$ 314.6	$ 296.6	$ 80.3	$ 86.9
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 287.3	$ 280.6	$ 96.8	$ 97.8
Actual Gain on Plan Assets	34.6	18.8	18.5	4.1
Company Contributions	9.1	8.4	—	—
Participant Contributions	—	—	2.5	2.4
Benefit Payments	(19.3)	(20.5)	(7.4)	(7.5)
Fair Value of Plan Assets as of December 31,	$ 311.7	$ 287.3	$ 110.4	$ 96.8
Funded (Underfunded) Status as of December 31,	$ (2.9)	$ (9.3)	$ 30.1	$ 9.9

Amounts Recognized on the Balance Sheets

	Pension Plans	OPEB

AEP	2017	2016	2017	2016
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 36.3	$ —	$ 463.0	$ 154.5
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.2)	(5.9)	(3.2)	(3.0)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(71.8)	(252.6)	(59.3)	(53.0)
Funded (Underfunded) Status	$ (41.7)	$ (258.5)	$ 400.5	$ 98.5

	Pension Plans		OPEB	
	December 31,			
AEP Texas	2017	2016	2017	2016
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 18.6	$ —	$ 40.2	$ 13.7
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(3.6)	(4.7)	—	—
Funded (Underfunded) Status	$ 14.6	$ (5.1)	$ 40.2	$ 13.7

	Pension Plans		OPEB	
	December 31,			
APCo	2017	2016	2017	2016
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 74.6	$ 25.2
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.5)	(2.4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(13.3)	(47.6)	(35.2)	(31.5)
Funded (Underfunded) Status	$ (13.3)	$ (47.6)	$ 36.9	$ (8.7)

	Pension Plans		OPEB	
	December 31,			
I&M	2017	2016	2017	2016
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 13.4	$ —	$ 57.6	$ 19.0
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.0)	(25.5)	—	—
Funded (Underfunded) Status	$ 12.4	$ (25.5)	$ 57.6	$ 19.0

	Pension Plans		OPEB	
	December 31,			
OPCo	2017	2016	2017	2016

	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 8.4	$ —	$ 54.2	$ 18.6
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.4)	(19.1)	—	—
Funded (Underfunded) Status	$ 8.0	$ (19.1)	$ 54.2	$ 18.6

PSO	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 13.9	$ 1.6	$ 26.1	$ 8.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.2)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(2.5)	(2.1)	—	—
Funded (Underfunded) Status	$ 11.2	$ (0.7)	$ 26.1	$ 8.8

SWEPCo	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 30.1	$ 9.9
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.1)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(2.7)	(9.2)	—	—
Funded (Underfunded) Status	$ (2.9)	$ (9.3)	$ 30.1	$ 9.9

Amounts Included in AOCI, Income Tax Expense and Regulatory Assets

AEP	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 1,354.2	$ 1,569.8	$ 309.9	$ 614.4
Prior Service Cost (Credit)	—	1.0	(416.3)	(485.4)
Recorded as				
Regulatory Assets	$ 1,271.3	$ 1,415.6	$ (82.4)	$ 90.4
Deferred Income Taxes	17.4	54.4	(5.0)	13.5
Net of Tax AOCI	53.9	100.8	(15.6)	25.1
Income Tax Expense (a)	11.6	—	(3.4)	—

AEP Texas

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 175.2	$ 193.3	$ 23.9	$ 50.7
Prior Service Credit	—	—	(35.4)	(41.2)
Recorded as				
Regulatory Assets	$ 161.4	$ 178.5	$ (10.2)	$ 9.7
Deferred Income Taxes	2.9	5.2	(0.3)	(0.1)
Net of Tax AOCI	8.9	9.6	(0.8)	(0.1)
Income Tax Expense (a)	2.0	—	(0.2)	—

APCo

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 182.5	$ 216.2	$ 48.0	$ 92.9
Prior Service Cost (Credit)	—	0.2	(60.4)	(70.5)
Recorded as				
Regulatory Assets	$ 179.9	$ 213.7	$ (11.1)	$ 7.7
Deferred Income Taxes	0.5	1.0	(0.3)	5.1
Net of Tax AOCI	1.7	1.7	(0.8)	9.6
Income Tax Expense (a)	0.4	—	(0.2)	—

I&M

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 94.9	$ 133.2	$ 42.0	$ 81.3
Prior Service Cost (Credit)	—	0.2	(56.9)	(66.3)
Recorded as				
Regulatory Assets	$ 91.8	$ 128.2	$ (14.0)	$ 13.7
Deferred Income Taxes	0.7	1.8	(0.2)	0.5
Net of Tax AOCI	2.0	3.4	(0.6)	0.8
Income Tax Expense (a)	0.4	—	(0.1)	—

OPCo

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 189.6	$ 215.4	$ 22.6	$ 58.2

Prior Service Cost (Credit)	—	0.1	(41.6)	(48.5)
Recorded as				
Regulatory Assets	$ 189.6	$ 215.5	$ (19.0)	$ 9.7

PSO

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 78.8	$ 91.0	$ 19.8	$ 37.3
Prior Service Credit	—	—	(25.9)	(30.2)
Recorded as				
Regulatory Assets	$ 78.8	$ 91.0	$ (6.1)	$ 7.1

SWEPCo

	Pension Plans		OPEB	
	December 31,			
	2017	2016	2017	2016
Components	(in millions)			
Net Actuarial Loss	$ 97.4	$ 103.8	$ 24.7	$ 45.4
Prior Service Cost (Credit)	—	0.1	(31.4)	(36.6)
Recorded as				
Regulatory Assets	$ 97.4	$ 103.9	$ (3.7)	$ 5.7
Deferred Income Taxes	—	—	(0.6)	1.1
Net of Tax AOCI	—	—	(2.0)	2.0
Income Tax Expense (a)	—	—	(0.4)	—

(a) Amounts relate to the re-measurement of Deferred Income Taxes as a result of Tax Reform. In accordance with the accounting guidance for “Income Taxes”, re-measurement of Deferred Income Taxes related to AOCI must flow through the statement of income.

Components of the change in amounts included in AOCI, Income Tax Expense and Regulatory Assets by Registrant are as follows:

AEP

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (132.8)	$ 107.5	$ (267.8)	$ 68.4
Amortization of Actuarial Loss	(82.8)	(83.8)	(36.7)	(31.4)
Amortization of Prior Service Credit (Cost)	(1.0)	(2.3)	69.1	69.0
Change for the Year Ended December 31,	$ (216.6)	$ 21.4	$ (235.4)	$ 106.0

AEP Texas

	Pension Plans		OPEB	
	2017	2016	2017	2016

Components	Pension Plans 2017	Pension Plans 2016	OPEB 2017	OPEB 2016
	(in millions)			
Actuarial (Gain) Loss During the Year	$ (11.1)	$ 7.1	$ (23.6)	$ 6.4
Amortization of Actuarial Loss	(7.0)	(7.1)	(3.2)	(2.8)
Amortization of Prior Service Credit (Cost)	—	(0.4)	5.8	6.0
Change for the Year Ended December 31,	$ (18.1)	$ (0.4)	$ (21.0)	$ 9.6

APCo

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (23.3)	$ 6.2	$ (38.6)	$ 11.4
Amortization of Actuarial Loss	(10.4)	(10.8)	(6.3)	(5.4)
Amortization of Prior Service Credit (Cost)	(0.2)	(0.1)	10.1	10.1
Change for the Year Ended December 31,	$ (33.9)	$ (4.7)	$ (34.8)	$ 16.1

I&M

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (28.6)	$ 13.2	$ (34.9)	$ 7.9
Amortization of Actuarial Loss	(9.7)	(10.0)	(4.4)	(3.7)
Amortization of Prior Service Credit (Cost)	(0.2)	(0.1)	9.4	9.4
Change for the Year Ended December 31,	$ (38.5)	$ 3.1	$ (29.9)	$ 13.6

OPCo

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (18.0)	$ 1.5	$ (31.3)	$ 9.4
Amortization of Actuarial Loss	(7.8)	(8.1)	(4.3)	(3.8)
Amortization of Prior Service Credit (Cost)	(0.1)	(0.1)	6.9	6.9
Change for the Year Ended December 31,	$ (25.9)	$ (6.7)	$ (28.7)	$ 12.5

PSO

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (7.9)	$ 1.3	$ (15.5)	$ 3.9
Amortization of Actuarial Loss	(4.3)	(4.4)	(2.0)	(1.8)
Amortization of Prior Service Credit (Cost)	—	(0.3)	4.3	4.3
Change for the Year Ended December 31,	$ (12.2)	$ (3.4)	$ (13.2)	$ 6.4

SWEPCo

	Pension Plans		OPEB	
	2017	2016	2017	2016
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (1.5)	$ 11.5	$ (18.4)	$ 4.0
Amortization of Actuarial Loss	(4.9)	(4.8)	(2.3)	(1.9)
Amortization of Prior Service Credit (Cost)	(0.1)	(0.3)	5.2	5.0

Change for the Year Ended December 31,	$ (6.5)	$ 6.4	$ (15.5)	$ 7.1

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to the Registrant Subsidiaries using the percentages in the table below:

	Pension Plan		OPEB	
	December 31,			
Company	**2017**	**2016**	**2017**	**2016**
AEP Texas	8.8%	8.6%	8.5%	8.7%
APCo	12.6%	12.6%	15.8%	16.0%
I&M	12.3%	12.1%	12.2%	12.1%
OPCo	9.8%	9.8%	11.5%	11.8%
PSO	5.6%	5.5%	5.5%	5.6%
SWEPCo	6.0%	6.0%	6.4%	6.3%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 318.6	$ —	$ —	$ —	$ 318.6	6.2 %
International	507.7	—	—	—	507.7	9.8 %
Options	—	26.9	—	—	26.9	0.5 %
Common Collective Trusts (c)	—	—	—	452.9	452.9	8.7 %
Subtotal – Equities	826.3	26.9	—	452.9	1,306.1	25.2 %
Fixed Income:						
United States Government and Agency Securities	—	1,376.5	—	—	1,376.5	26.6 %
Corporate Debt	—	1,277.0	—	—	1,277.0	24.7 %
Foreign Debt	—	296.9	—	—	296.9	5.7 %
State and Local Government	—	31.7	—	—	31.7	0.6 %
Other – Asset Backed	—	10.2	—	—	10.2	0.2 %
Subtotal – Fixed Income	—	2,992.3	—	—	2,992.3	57.8 %
Infrastructure (c)	—	—	—	59.5	59.5	1.2 %

Real Estate (c)	—	—	—	290.3	290.3	5.6 %
Alternative Investments (c)	—	—	—	446.0	446.0	8.6 %
Securities Lending	—	501.8	—	—	501.8	9.7 %
Securities Lending Collateral (a)	—	—	—	(503.5)	(503.5)	(9.7)%
Cash and Cash Equivalents (c)	0.4	35.6	—	21.2	57.2	1.1 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	24.4	24.4	0.5 %
Total	$ 826.7	$ 3,556.6	$ —	$ 790.8	$ 5,174.1	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Infrastructure	Real Estate	Alternative Investments	Total Level 3
	(in millions)			
Balance as of January 1, 2017	$ 57.6	$ 254.9	$ 411.1	$ 723.6
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	—	—	—	—
Relating to Assets Sold During the Period	—	—	—	—
Purchases and Sales	—	—	—	—
Transfers into Level 3	—	—	—	—
Transfers out of Level 3 (a)	(57.6)	(254.9)	(411.1)	(723.6)
Balance as of December 31, 2017	$ —	$ —	$ —	$ —

(a) The classification of Level 3 assets from the prior year was corrected in the current year presentation and included within the fair value hierarchy table as of December 31, 2017 as "Other" investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). Management concluded that these disclosure errors were immaterial individually and in the aggregate to all prior periods presented.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities:						
Domestic	$ 307.1	$ —	$ —	$ —	$ 307.1	17.7 %
International	306.9	—	—	—	306.9	17.7 %
Options	—	9.4	—	—	9.4	0.5 %
Common Collective Trusts (b)	—	—	—	153.6	153.6	8.9 %
Subtotal – Equities	614.0	9.4	—	153.6	777.0	44.8 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	185.0	185.0	10.7 %

United States Government and Agency Securities	—	187.4	—	—	187.4	10.8 %
Corporate Debt	—	214.1	—	—	214.1	12.4 %
Foreign Debt	—	40.7	—	—	40.7	2.4 %
State and Local Government	49.7	16.8	—	—	66.5	3.8 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	49.7	459.2	—	185.0	693.9	40.1 %
Trust Owned Life Insurance:						
International Equities	—	105.4	—	—	105.4	6.1 %
United States Bonds	—	118.2	—	—	118.2	6.8 %
Subtotal – Trust Owned Life Insurance	—	223.6	—	—	223.6	12.9 %
Cash and Cash Equivalents (b)	36.7	—	—	4.2	40.9	2.4 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.9)	(2.9)	(0.2)%
Total	$ 700.4	$ 692.2	$ —	$ 339.9	$ 1,732.5	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 357.8	$ —	$ —	$ —	$ 357.8	7.4 %
International	439.2	—	—	—	439.2	9.1 %
Options	—	20.0	—	—	20.0	0.4 %
Common Collective Trusts (c)	—	14.0	—	400.5	414.5	8.6 %
Subtotal – Equities	797.0	34.0	—	400.5	1,231.5	25.5 %
Fixed Income:						
Common Collective Trust – Debt (c)	—	—	—	32.3	32.3	0.7 %
United States Government and Agency Securities (c)	—	423.3	—	17.7	441.0	9.1 %
Corporate Debt (c)	—	1,932.2	—	10.0	1,942.2	40.2 %
Foreign Debt (c)	—	373.7	—	12.1	385.8	8.0 %
State and Local Government	—	11.5	—	—	11.5	0.2 %
Other – Asset Backed (c)	—	5.4	—	7.4	12.8	0.3 %
Subtotal – Fixed Income	—	2,746.1	—	79.5	2,825.6	58.5 %
Infrastructure	—	—	57.6	—	57.6	1.2 %
Real Estate	—	—	254.9	—	254.9	5.3 %

Alternative Investments	—	—	411.1	—	411.1	8.5 %
Securities Lending	—	161.6	—	—	161.6	3.4 %
Securities Lending Collateral (a)	—	—	—	(163.3)	(163.3)	(3.4)%
Cash and Cash Equivalents (c)	—	—	—	29.7	29.7	0.6 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	18.6	18.6	0.4 %
Total	$ 797.0	$ 2,941.7	$ 723.6	$ 365.0	$ 4,827.3	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2016	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	5.9	5.3	13.7	24.9
Relating to Assets Sold During the Period	—	0.9	23.2	21.1	45.2
Purchases and Sales	(0.1)	8.8	(27.3)	(2.4)	(21.0)
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2016	$ —	$ 57.6	$ 254.9	$ 411.1	$ 723.6

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 517.1	$ —	$ —	$ —	$ 517.1	33.5 %
International	435.5	—	—	—	435.5	28.2 %
Options	—	15.2	—	—	15.2	1.0 %
Common Collective Trusts (b)	—	10.9	—	20.5	31.4	2.0 %
Subtotal – Equities	952.6	26.1	—	20.5	999.2	64.7 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	93.7	93.7	6.0 %
United States Government and Agency Securities	—	64.7	—	—	64.7	4.2 %
Corporate Debt	—	121.6	—	—	121.6	7.9 %
Foreign Debt	—	18.6	—	—	18.6	1.2 %
State and Local Government	—	3.0	—	—	3.0	0.2 %

Other – Asset Backed	—	5.9	—	—	5.9	0.4 %
Subtotal – Fixed Income	—	213.8	—	93.7	307.5	19.9 %
Trust Owned Life Insurance:						
International Equities (b)	—	—	—	110.1	110.1	7.1 %
United States Bonds (b)	—	—	—	97.4	97.4	6.3 %
Subtotal – Trust Owned Life Insurance	—	—	—	207.5	207.5	13.4 %
Cash and Cash Equivalents	24.0	10.5	—	—	34.5	2.2 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.8)	(2.8)	(0.2)%
Total	$ 976.6	$ 250.4	$ —	$ 318.9	$ 1,545.9	100.0 %

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,951.3	$ 421.4	$ 648.0	$ 592.4	$ 483.4	$ 256.9	$ 289.4
Nonqualified Pension Plans	73.9	3.8	0.2	0.4	0.1	2.7	2.2
Total as of December 31, 2017	$ 5,025.2	$ 425.2	$ 648.2	$ 592.8	$ 483.5	$ 259.6	$ 291.6

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,846.0	$ 404.7	$ 641.0	$ 588.5	$ 478.0	$ 252.0	$ 279.8
Nonqualified Pension Plans	69.8	3.8	0.3	0.3	—	2.2	1.7
Total as of December 31, 2016	$ 4,915.8	$ 408.5	$ 641.3	$ 588.8	$ 478.0	$ 254.2	$ 281.5

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans were as follows:

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 78.0	$ 4.0	$ 0.4	$ 1.0	$ 0.4	$ 2.7	$ 2.2
Accumulated Benefit Obligation	$ 73.9	$ 3.8	$ 0.2	$ 0.4	$ 0.1	$ 2.7	$ 2.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2017	$ (73.9)	$ (3.8)	$ (0.2)	$ (0.4)	$ (0.1)	$ (2.7)	$ (2.2)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			

Projected Benefit Obligation	$ 5,085.8	$ 3.8	$ 654.0	$ 611.6	$ 492.9	$ 2.3	$ 1.7
Accumulated Benefit Obligation	$ 4,915.8	$ 3.8	$ 641.3	$ 588.8	$ 478.0	$ 2.2	$ 1.7
Fair Value of Plan Assets	4,827.3	—	606.4	586.1	473.8	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2016	$ (88.5)	$ (3.8)	$ (34.9)	$ (2.7)	$ (4.2)	$ (2.2)	$ (1.7)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2018:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 100.7	$ 4.2
AEP Texas	3.6	—
APCo	9.6	2.5
I&M	1.6	—
OPCo	1.2	—
PSO	0.2	—
SWEPCo	2.8	—

The tables below reflect the total benefits expected to be paid from the plan or from the Registrants' assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2018	$ 333.2	$ 31.0	$ 42.9	$ 35.1	$ 35.1	$ 18.6	$ 20.8
2019	340.1	31.0	43.9	37.2	35.0	19.5	21.6
2020	345.0	33.7	43.5	37.6	35.1	19.8	21.8
2021	356.2	34.7	44.4	38.7	34.3	21.7	23.2
2022	356.8	33.5	44.6	40.4	35.0	21.1	23.3
Years 2023 to 2027, in Total	1,795.4	165.6	221.3	210.8	165.6	104.3	121.5

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2018	$ 122.8	$ 10.2	$ 23.3	$ 14.9	$ 14.6	$ 6.5	$ 7.1
2019	123.1	10.4	22.8	14.9	14.7	6.6	7.1
2020	124.0	10.5	22.8	15.0	14.6	6.8	7.4
2021	124.6	10.7	22.6	15.2	14.5	6.8	7.6
2022	124.6	10.8	22.3	15.2	14.5	6.8	7.7

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Years 2023 to 2027, in Total	616.4	53.7	106.2	74.8	69.6	34.7	40.4

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
2018	$ 0.3	$ —	$ 0.2	$ —	$ —	$ —	$ —
2019	0.3	—	0.2	—	—	—	—
2020	0.3	—	0.2	—	—	—	—
2021	0.3	—	0.2	—	—	—	—
2022	0.3	—	0.2	—	—	—	—
Years 2023 to 2027, in Total	1.7	—	0.9	—	—	—	—

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans:

AEP	Pension Plans			OPEB		
	Years Ended December 31,					
	2017	2016	2015	2017	2016	2015
	(in millions)					
Service Cost	$ 96.5	$ 85.8	$ 93.5	$ 11.2	$ 10.2	$ 12.2
Interest Cost	203.1	211.6	205.3	59.3	60.9	56.8
Expected Return on Plan Assets	(284.8)	(280.3)	(274.8)	(101.3)	(107.0)	(111.0)
Amortization of Prior Service Cost (Credit)	1.0	2.3	2.2	(69.1)	(69.0)	(69.1)
Amortization of Net Actuarial Loss	82.8	83.8	107.1	36.7	31.4	18.8
Net Periodic Benefit Cost (Credit)	98.6	103.2	133.3	(63.2)	(73.5)	(92.3)
Capitalized Portion	(39.9)	(37.8)	(48.4)	25.6	26.9	33.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 58.7	$ 65.4	$ 84.9	$ (37.6)	$ (46.6)	$ (58.8)

AEP Texas	Pension Plans			OPEB		
	Years Ended December 31,					
	2017	2016	2015	2017	2016	2015
	(in millions)					
Service Cost	$ 8.6	$ 7.5	$ 7.6	$ 0.9	$ 0.7	$ 0.8
Interest Cost	17.1	17.8	17.2	4.9	5.1	4.8
Expected Return on Plan Assets	(25.0)	(24.5)	(24.1)	(8.8)	(9.3)	(9.9)
Amortization of Prior Service Cost (Credit)	—	0.4	0.3	(5.8)	(6.0)	(5.9)
Amortization of Net Actuarial Loss	7.0	7.1	9.0	3.2	2.8	1.5
Net Periodic Benefit Cost (Credit)	7.7	8.3	10.0	(5.6)	(6.7)	(8.7)
Capitalized Portion	(4.0)	(3.6)	(4.7)	2.9	3.4	4.1
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.7	$ 4.7	$ 5.3	$ (2.7)	$ (3.3)	$ (4.6)

APCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2017	2016	2015	2017	2016	2015
	(in millions)					

	Pension Plans 2017	Pension Plans 2016	Pension Plans 2015	OPEB 2017	OPEB 2016	OPEB 2015
Service Cost	$ 9.4	$ 8.1	$ 8.7	$ 1.1	$ 1.0	$ 1.1
Interest Cost	25.7	27.2	26.7	10.6	10.8	10.3
Expected Return on Plan Assets	(35.8)	(35.3)	(35.0)	(16.5)	(17.3)	(18.1)
Amortization of Prior Service Cost (Credit)	0.2	0.1	0.2	(10.1)	(10.1)	(10.0)
Amortization of Net Actuarial Loss	10.4	10.8	13.9	6.3	5.4	3.6
Net Periodic Benefit Cost (Credit)	9.9	10.9	14.5	(8.6)	(10.2)	(13.1)
Capitalized Portion	(4.0)	(4.1)	(5.5)	3.5	3.9	5.0
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 5.9	$ 6.8	$ 9.0	$ (5.1)	$ (6.3)	$ (8.1)

I&M

	Pension Plans			OPEB		
	Years Ended December 31,					
	2017	2016	2015	2017	2016	2015
	(in millions)					
Service Cost	$ 14.0	$ 12.2	$ 12.9	$ 1.6	$ 1.5	$ 1.6
Interest Cost	24.3	25.3	24.5	6.9	7.0	6.4
Expected Return on Plan Assets	(34.6)	(33.6)	(32.6)	(12.2)	(12.9)	(13.2)
Amortization of Prior Service Cost (Credit)	0.2	0.1	0.2	(9.4)	(9.4)	(9.4)
Amortization of Net Actuarial Loss	9.7	10.0	12.6	4.4	3.7	2.0
Net Periodic Benefit Cost (Credit)	13.6	14.0	17.6	(8.7)	(10.1)	(12.6)
Capitalized Portion	(5.5)	(3.3)	(4.0)	3.5	2.4	2.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 8.1	$ 10.7	$ 13.6	$ (5.2)	$ (7.7)	$ (9.7)

OPCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2017	2016	2015	2017	2016	2015
	(in millions)					
Service Cost	$ 7.5	$ 6.5	$ 6.7	$ 0.9	$ 0.8	$ 0.9
Interest Cost	19.4	20.6	20.3	6.7	7.0	6.4
Expected Return on Plan Assets	(27.9)	(27.6)	(27.5)	(11.9)	(13.0)	(13.4)
Amortization of Prior Service Cost (Credit)	0.1	0.1	0.2	(6.9)	(6.9)	(7.0)
Amortization of Net Actuarial Loss	7.8	8.1	10.5	4.3	3.8	2.1
Net Periodic Benefit Cost (Credit)	6.9	7.7	10.2	(6.9)	(8.3)	(11.0)
Capitalized Portion	(3.3)	(3.4)	(4.8)	3.3	3.7	5.2
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.6	$ 4.3	$ 5.4	$ (3.6)	$ (4.6)	$ (5.8)

PSO

	Pension Plans			OPEB		
	Years Ended December 31,					
	2017	2016	2015	2017	2016	2015
	(in millions)					
Service Cost	$ 6.4	$ 6.2	$ 6.4	$ 0.7	$ 0.6	$ 0.7
Interest Cost	10.7	11.2	10.9	3.2	3.3	3.0
Expected Return on Plan Assets	(15.6)	(15.5)	(15.1)	(5.6)	(6.1)	(6.3)
Amortization of Prior Service Cost (Credit)	—	0.3	0.2	(4.3)	(4.3)	(4.3)

Amortization of Net Actuarial Loss	4.3	4.4	5.7	2.0	1.8	1.0
Net Periodic Benefit Cost (Credit)	5.8	6.6	8.1	(4.0)	(4.7)	(5.9)
Capitalized Portion	(2.1)	(2.4)	(2.8)	1.4	1.7	2.0
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.7	$ 4.2	$ 5.3	$ (2.6)	$ (3.0)	$ (3.9)

SWEPCo	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
	(in millions)					
Service Cost	$ 8.7	$ 8.1	$ 8.3	$ 0.9	$ 0.8	$ 0.8
Interest Cost	12.3	12.4	11.8	3.6	3.6	3.4
Expected Return on Plan Assets	(17.0)	(16.4)	(16.0)	(6.3)	(6.8)	(6.9)
Amortization of Prior Service Cost (Credit)	0.1	0.3	0.3	(5.2)	(5.0)	(5.2)
Amortization of Net Actuarial Loss	4.9	4.8	6.0	2.3	1.9	1.1
Net Periodic Benefit Cost (Credit)	9.0	9.2	10.4	(4.7)	(5.5)	(6.8)
Capitalized Portion	(2.7)	(2.7)	(3.2)	1.4	1.6	2.1
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 6.3	$ 6.5	$ 7.2	$ (3.3)	$ (3.9)	$ (4.7)

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on each Registrants' balance sheet during 2018 are shown in the following tables:

	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Pension Plans – Components	**(in millions)**						
Net Actuarial Loss	$ 85.5	$ 7.2	$ 10.8	$ 10.1	$ 8.1	$ 4.5	$ 5.1
Total Estimated 2018 Amortization	$ 85.5	$ 7.2	$ 10.8	$ 10.1	$ 8.1	$ 4.5	$ 5.1
Pension Plans – Expected to be Recorded as							
Regulatory Asset	$ 75.9	$ 6.8	$ 10.8	$ 9.5	$ 8.1	$ 4.5	$ 5.1
Deferred Income Taxes	2.0	0.1	—	0.1	—	—	—
Net of Tax AOCI	7.6	0.3	—	0.5	—	—	—
Total	$ 85.5	$ 7.2	$ 10.8	$ 10.1	$ 8.1	$ 4.5	$ 5.1

	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
OPEB – Components	**(in millions)**						
Net Actuarial Loss	$ 9.8	$ 0.7	$ 1.9	$ 1.0	$ 1.0	$ 0.5	$ 0.6
Prior Service Credit	(69.1)	(5.8)	(10.1)	(9.4)	(6.9)	(4.3)	(5.2)
Total Estimated 2018 Amortization	$ (59.3)	$ (5.1)	$ (8.2)	$ (8.4)	$ (5.9)	$ (3.8)	$ (4.6)
OPEB – Expected to be Recorded as							
Regulatory Asset	$ (42.9)	$ (5.1)	$ (4.2)	$ (7.6)	$ (5.9)	$ (3.8)	$ (2.8)
Deferred Income Taxes	(3.5)	—	(0.8)	(0.2)	—	—	(0.4)
Net of Tax AOCI	(12.9)	—	(3.2)	(0.6)	—	—	(1.4)
Total	$ (59.3)	$ (5.1)	$ (8.2)	$ (8.4)	$ (5.9)	$ (3.8)	$ (4.6)

American Electric Power System Retirement Savings Plan

AEP sponsors the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not covered by a retirement savings plan of the United Mine Workers of America (UMWA). This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant:

Company	Year Ended December 31, 2017	2016	2015
	(in millions)		
AEP	$ 74.6	$ 72.9	$ 73.6
AEP Texas	6.0	5.2	5.0
APCo	7.4	7.3	7.2
I&M	10.7	10.9	10.6
OPCo	6.1	5.6	5.4
PSO	5.0	4.3	4.2
SWEPCo	6.0	5.7	5.7

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan was in Critical and Declining Status for the plan years ending June 30, 2017 and 2016, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in February 2015 which was updated in May 2016, August 2016 and May 2017.

The amounts contributed in 2017, 2016 and 2015 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2016. UMWA pension contributions included a surcharge of 5% from December 2014 through June 2015. UMWA pension contributions included a surcharge of 10% from July 2015 through June 2016 at which time new base contribution rates went into effect with no associated surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the February 28, 2018 expiration of the current collective bargaining agreement, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

Based upon the planned closure of Cook Coal Terminal in 2022, AEP records a UMWA pension withdrawal liability on the balance sheet. The UMWA pension withdrawal liability is re-measured annually and is related to the company's proportionate share of the plan's unfunded vested liabilities. As of December 31, 2017 and 2016, the liability balance was $19 million and $39 million, respectively. AEP recovers the estimated UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. A regulatory asset is recorded on the balance sheet when the UMWA pension withdrawal liability exceeds the cumulative billings collected. As of December 31, 2017 and 2016, the regulatory asset balance was $1 million and $20 million, respectively. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. BUSINESS SEGMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP's Reportable 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 AEP Texas and OPCo.
- 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 AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's 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.
- Contracted renewable energy investments and management services.

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 7 for additional information.

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2017, 2016 and 2015 and reportable segment balance sheet information as of December 31, 2017 and 2016.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2017							
Revenues from:							
External Customers	$ 9,095.1	$ 4,328.9	$ 178.4	$ 1,771.4	$ 51.1	$ —	$ 15,424.9
Other Operating Segments	96.9	90.4	588.3	103.7	69.7	(949.0)	—
Total Revenues	$ 9,192.0	$ 4,419.3	$ 766.7	$ 1,875.1	$ 120.8	$ (949.0)	$ 15,424.9
Asset Impairments and Other Related Charges	$ 33.6	$ —	$ —	$ 53.5	$ —	$ —	$ 87.1
Depreciation and Amortization	1,142.5	667.5	102.2	24.2	0.3	60.5 (b)	1,997.2
Interest and Investment Income	6.8	7.7	1.2	10.3	23.3	(33.3)	16.0
Carrying Costs Income	15.2	3.6	(0.2)	—	—	—	18.6
Interest Expense	540.0	244.1	72.8	18.5	63.9	(44.3) (b)	895.0
Income Tax Expense (Credit)	425.6	127.2	189.8	189.7	37.4	—	969.7
Income (Loss) from Continuing Operations	$ 803.3	$ 636.4	$ 355.6	$ 166.0	$ (32.4)	$ —	$ 1,928.9
Income (Loss) from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$ 803.3	$ 636.4	$ 355.6	$ 166.0	$ (32.4)	$ —	$ 1,928.9
Gross Property Additions	$ 2,343.2	$ 1,558.4	$ 1,542.8	$ 328.5	$ 15.6	$ (90.4)	$ 5,698.1
Total Property, Plant and Equipment	$ 43,294.4	$ 16,371.2	$ 7,110.2	$ 644.6	$ 374.5	$ (366.4) (b)	$ 67,428.5
Accumulated Depreciation and Amortization	13,153.4	3,768.3	176.6	75.0	180.6	(186.9) (b)	17,167.0
Total Property, Plant and Equipment – Net	$ 30,141.0	$ 12,602.9	$ 6,933.6	$ 569.6	$ 193.9	$ (179.5) (b)	$ 50,261.5

Total Assets	$ 37,579.7	$ 16,060.7	$ 8,141.8	$ 2,009.8	$ 3,959.1 (c)	$ (3,022.0) (b) (d)	$ 64,729.1
Investments in Equity Method Investees	$ 37.1	$ 1.5	$ 742.9	$ 16.6	$ 14.2	$ —	$ 812.3
Long-term Debt Due Within One Year:							
Non-Affiliated	$ 1,038.1	$ 663.1	$ 50.0	$ —	$ 2.5	$ —	$ 1,753.7
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Non-Affiliated	10,801.4	4,705.4	2,631.3	(0.3)	1,281.8	—	19,419.6
Total Long-term Debt	$ 11,889.5	$ 5,368.5	$ 2,681.3	$ 31.9	$ 1,284.3	$ (82.2)	$ 21,173.3

2016	**Vertically Integrated Utilities**	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other (a)**	**Reconciling Adjustments**	**Consolidated**
				(in millions)			
Revenues from:							
External Customers	$ 9,012.4	$ 4,328.3	$ 145.9	$ 2,858.7	$ 34.8	$ —	$ 16,380.1
Other Operating Segments	79.5	94.1	366.9	127.3	70.3	(738.1)	—
Total Revenues	$ 9,091.9	$ 4,422.4	$ 512.8	$ 2,986.0	$ 105.1	$ (738.1)	$ 16,380.1
Asset Impairments and Other Related Charges	$ 10.5	$ —	$ —	$ 2,257.3	$ —	$ —	$ 2,267.8
Depreciation and Amortization	1,073.8	649.9	67.1	154.6	0.2	16.7 (b)	1,962.3
Interest and Investment Income	4.8	14.8	0.4	1.4	11.8	(16.9)	16.3
Carrying Costs Income	10.5	20.0	(0.3)	—	—	(14.0)	16.2
Interest Expense	522.1	256.9	50.3	35.8	40.5	(28.4) (b)	877.2
Income Tax Expense (Credit)	397.3	205.1	134.1	(666.5)	(143.7)	—	(73.7)
Income (Loss) from Continuing Operations	$ 984.0	$ 482.1	$ 269.3	$ (1,198.0)	$ 83.1	$ —	$ 620.5
Income (Loss) from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$ 984.0	$ 482.1	$ 269.3	$ (1,198.0)	$ 80.6	$ —	$ 618.0
Gross Property Additions	$ 2,237.0	$ 1,058.3	$ 1,265.8	$ 336.2	$ 9.8	$ (18.1)	$ 4,889.0
Total Property, Plant and Equipment	$ 41,552.6	$ 14,762.2	$ 5,354.0	$ 364.7	$ 356.6	$ (353.5) (b)	$ 62,036.6
Accumulated Depreciation and Amortization	12,596.7	3,655.0	101.4	42.2	186.0	(184.0) (b)	16,397.3
Total Property, Plant and Equipment – Net	$ 28,955.9	$ 11,107.2	$ 5,252.6	$ 322.5	$ 170.6	$ (169.5) (b)	$ 45,639.3

Assets Held for Sale	$ —	$ —	$ —	$ 1,951.2	$ —	$ —	$ 1,951.2
Total Assets	$ 37,428.3	$ 14,802.4	$ 6,384.8	$ 3,386.1	$ 3,883.4 (c)	$ (2,417.3) (b) (d)	$ 63,467.7
Investments in Equity Method Investees	$ 41.2	$ 1.2	$ 742.0	$ 0.1	$ 24.9	$ —	$ 809.4
Long-term Debt Due Within One Year:							
Non-Affiliated	$ 1,519.9	$ 309.4	$ —	$ 500.1	$ 548.6	$ —	$ 2,878.0
Long-term Debt:							
Affiliated	20.0	—	—	32.2	—	(52.2)	—
Non-Affiliated	10,353.3	4,672.2	2,055.7	—	297.2	—	17,378.4
Total Long-term Debt	$ 11,893.2	$ 4,981.6	$ 2,055.7	$ 532.3	$ 845.8	$ (52.2)	$ 20,256.4
Liabilities Held for Sale	$ —	$ —	$ —	$ 235.9	$ —	$ —	$ 235.9

2015	**Vertically Integrated Utilities**	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other(a)**	**Reconciling Adjustments**	**Consolidated**
				(in millions)			
Revenues from:							
External Customers	$ 9,069.9	$ 4,392.0	$ 100.6	$ 2,866.7	$ 24.0	$ —	$ 16,453.2
Other Operating Segments	102.3	164.6	228.6	546.0	75.0	(1,116.5)	—
Total Revenues	$ 9,172.2	$ 4,556.6	$ 329.2	$ 3,412.7	$ 99.0	$ (1,116.5)	$ 16,453.2
Depreciation and Amortization	$ 1,062.6	$ 686.4	$ 43.0	$ 201.4	$ 0.8	$ 15.5 (b)	$ 2,009.7
Interest and Investment Income	4.6	6.4	0.2	2.8	9.2	(15.3)	7.9
Carrying Costs Income	11.8	11.8	(0.2)	—	—	0.1	23.5
Interest Expense	517.4	276.2	37.2	40.0	30.3	(27.2) (b)	873.9
Income Tax Expense (Credit)	449.3	185.5	91.3	194.6	(1.1)	—	919.6
Income (Loss) from Continuing Operations	$ 900.2	$ 352.4	$ 192.7	$ 366.0	$ (42.7)	$ —	$ 1,768.6
Income from Discontinued Operations, Net of Tax	—	—	—	—	283.7	—	283.7
Net Income	$ 900.2	$ 352.4	$ 192.7	$ 366.0	$ 241.0	$ —	$ 2,052.3
Gross Property Additions	$ 2,222.3	$ 1,048.4	$ 1,121.3	$ 134.3	$ 4.8	$ (17.8)	$ 4,513.3
Total Assets	$ 35,792.3	$ 14,795.0	$ 5,012.1	$ 5,414.5	$ 3,628.5 (c)	$ (2,959.3) (b) (d)	$ 61,683.1

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and discontinued operations of AEPRO and other nonallocated costs.

(b) Includes eliminations due to an intercompany capital lease.
(c) Includes the elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable.

Registrant Subsidiaries' Reportable Segments (Applies to all Registrant Subsidiaries except AEPTCo)

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an electricity transmission and distribution business for AEP Texas and OPCo. Other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

AEPTCo's Reportable Segments

AEPTCo Parent is the holding company of seven FERC-regulated transmission-only electric utilities (State Transcos). The seven State Transcos have been identified as operating segments of AEPTCo under the accounting guidance for "Segment Reporting." The State Transcos business consists of developing, constructing and operating transmission facilities at the request of the RTO's in which they operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. The State Transcos are regulated for rate-making purposes exclusively by FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

AEPTCo's Chief Operating Decision Maker makes operating decisions, allocates resources to and assesses performance based on these operating segments. The seven State Transcos operating segments all have similar economic characteristics and meet all of the criteria under the accounting guidance for "Segment Reporting" to be aggregated into one operating segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the years ended December 31, 2017, 2016 and 2015 and reportable segment balance sheet information as of December 31, 2017 and 2016.

2017	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 141.9	$ —	$ —	$ 141.9
Sales to AEP Affiliates	580.5	—	—	580.5
Other Revenues	0.8	—	—	0.8
Total Revenues	$ 723.2	$ —	$ —	$ 723.2
Depreciation and Amortization	$ 97.1	$ —	$ —	$ 97.1
Interest Income	0.7	82.9	(82.4) (a)	1.2
Allowance for Equity Funds Used During Construction	52.3	—	—	52.3
Interest Expense	68.0	82.4	(82.4) (a)	68.0
Income Tax Expense (Credit)	147.0	0.2	—	147.2
Net Income	$ 285.8	$ 0.3 (b)	$ —	$ 286.1
Gross Property Additions	$ 1,522.5	$ —	$ —	$ 1,522.5

Total Transmission Property	$	6,780.2	$	—		$	—		$	6,780.2
Accumulated Depreciation and Amortization		170.4		—			—			170.4
Total Transmission Property - Net	$	6,609.8	$	—		$	—		$	6,609.8
Notes Receivable - Affiliated	$	—	$	2,550.4		$	(2,550.4)	(c)	$	—
Total Assets	$	7,072.9	$	2,590.1	(d)	$	(2,594.9)	(e)	$	7,068.1
Total Long-Term Debt	$	2,575.0	$	2,550.4		$	(2,575.0)	(c)	$	2,550.4

2016	State Transcos		AEPTCo Parent			Reconciling Adjustments			AEPTCo Consolidated	
	(in millions)									
Revenues from:										
External Customers	$	110.4	$	—		$	—		$	110.4
Sales to AEP Affiliates		367.5		—			—			367.5
Other Revenues		0.1		—			—			0.1
Total Revenues	$	478.0	$	—		$	—		$	478.0
Depreciation and Amortization	$	65.9	$	—		$	—		$	65.9
Interest Income		0.1		57.8			(57.5)	(a)		0.4
Allowance for Equity Funds Used During Construction		52.3		—			—			52.3
Interest Expense		45.6		57.9			(57.5)	(a)		46.0
Income Tax Expense (Credit)		94.4		(0.3)			—			94.1
Net Income (Loss)	$	193.3	$	(0.6)	(b)	$	—		$	192.7
Gross Property Additions	$	1,166.0	$	—		$	—		$	1,166.0
Total Transmission Property	$	5,054.2	$	—		$	—		$	5,054.2
Accumulated Depreciation and Amortization		99.6		—			—			99.6
Total Transmission Property - Net	$	4,954.6	$	—		$	—		$	4,954.6
Notes Receivable - Affiliated	$	—	$	1,950.0		$	(1,950.0)	(c)	$	—
Total Assets	$	5,337.5	$	1,987.7	(d)	$	(1,975.4)	(e)		$5,349.8
Total Long-Term Debt	$	1,932.0	$	1,950.0		$	(1,950.0)	(c)		$1,932.0

2015	State Transcos		AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated	
	(in millions)							
Revenues from:								
External Customers	$	84.3	$	—	$	—	$	84.3
Sales to AEP Affiliates		225.6		—		—		225.6
Other		0.3		—		—		0.3

Total Revenues	$	310.2	$	—		$	—		$	310.2
Depreciation and Amortization	$	42.4	$	—		$	—		$	42.4
Interest Income		0.1		49.6			(49.6)	(a)		0.1
Allowance for Equity Funds Used During Construction		53.0		—			—			53.0
Interest Expense		34.4		49.8			(49.6)	(a)		34.6
Income Tax Expense (Credit)		60.1		(0.1)			—			60.0
Net Income (Loss)	$	133.2	$	(0.3)	(b)	$	—		$	132.9
Gross Property Additions	$	1,008.9	$	—		$	—		$	1,008.9
Total Assets	$	4,143.6	$	1,588.4	(d)	$	(1,575.5)	(e)	$	4,156.5

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Includes the elimination of AEPTCo Parent's equity earnings in State Transcos.
(c) Elimination of intercompany debt.
(d) Includes the elimination of AEPTCo Parent's investments in State Transcos.
(e) Primarily relates to the elimination of Notes Receivable from the State Transcos.

10. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise. For the periods presented, AEPTCo did not have any Derivative and Hedging activity.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk, credit risk and foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, the Registrants primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

The Registrants utilize power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." 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.

The following tables represent the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments
December 31, 2017

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	358.7	—	57.4	38.5	10.4	10.3	22.7
Coal	Tons	2.0	—	—	2.0	—	—	—
Natural Gas	MMBtus	53.7	—	1.1	0.7	—	—	18.3
Heating Oil and Gasoline	Gallons	6.9	1.4	1.3	0.7	1.6	0.7	0.8
Interest Rate	USD	$ 50.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2016

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	348.0	—	51.9	19.9	11.2	11.9	14.2
Coal	Tons	1.5	—	—	0.5	—	—	1.0
Natural Gas	MMBtus	32.8	—	—	—	—	—	—
Heating Oil and Gasoline	Gallons	7.4	1.5	1.4	0.7	1.6	0.8	0.9
Interest Rate	USD	$ 75.2	$ —	$ 0.1	$ 0.1	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrants apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. AEP netted cash collateral received from third parties against short-term and long-term risk management assets in the amounts of $9.4 million and $7.9 million for the years ended December 31, 2017 and 2016. AEP netted cash collateral paid to third parties against short-term and long-term risk management liabilities in the amounts of $9 million and$7.6 million for the years ended December 31, 2017 and 2016. The netted cash collateral from third parties against short-term and long-term risk management assets and netted cash collateral paid to third parties against short-term and long-term risk management liabilities were immaterial for the other Registrants for the years ended December 31, 2017 and 2016.

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 389.0	$ 17.5	$ 2.5	$ 409.0	$ (282.8)	$ 126.2
Long-term Risk Management Assets	300.9	6.3	—	307.2	(25.1)	282.1
Total Assets	689.9	23.8	2.5	716.2	(307.9)	408.3
Current Risk Management Liabilities	334.6	9.0	—	343.6	(282.0)	61.6
Long-term Risk Management Liabilities	280.6	58.3	8.6	347.5	(25.5)	322.0
Total Liabilities	615.2	67.3	8.6	691.1	(307.5)	383.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 74.7	$ (43.5)	$ (6.1)	$ 25.1	$ (0.4)	$ 24.7

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 264.4	$ 13.2	$ —	$ 277.6	$ (183.1)	$ 94.5
Long-term Risk Management Assets	315.0	7.7	—	322.7	(33.6)	289.1
Total Assets	579.4	20.9	—	600.3	(216.7)	383.6
Current Risk Management Liabilities	227.2	6.3	—	233.5	(180.1)	53.4
Long-term Risk Management Liabilities	301.0	50.1	1.4	352.5	(36.3)	316.2
Total Liabilities	528.2	56.4	1.4	586.0	(216.4)	369.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 51.2	$ (35.5)	$ (1.4)	$ 14.3	$ (0.3)	$ 14.0

AEP Texas

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.5	$ —	$ 0.5
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	—	0.5

Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ 0.5	$ —	$ 0.5

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.4	$ (0.2)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	0.4	(0.2)	0.2
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.4	$ (0.2)	$ 0.2

APCo

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 75.6	$ (50.7)	$ 24.9
Long-term Risk Management Assets	2.4	(1.3)	1.1
Total Assets	78.0	(52.0)	26.0
Current Risk Management Liabilities	50.6	(49.3)	1.3
Long-term Risk Management Liabilities	1.4	(1.2)	0.2
Total Liabilities	52.0	(50.5)	1.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ 26.0	$ (1.5)	$ 24.5

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 22.7	$ (20.1)	$ 2.6
Long-term Risk Management Assets	1.9	(1.9)	—
Total Assets	24.6	(22.0)	2.6
Current Risk Management Liabilities	20.6	(20.3)	0.3
Long-term Risk Management Liabilities	2.8	(1.9)	0.9

Total Liabilities	23.4	(22.2)	1.2
Total MTM Derivative Contract Net Assets	$ 1.2	$ 0.2	$ 1.4

I&M

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 47.2	$ (39.6)	$ 7.6
Long-term Risk Management Assets	1.6	(0.9)	0.7
Total Assets	48.8	(40.5)	8.3
Current Risk Management Liabilities	48.5	(45.0)	3.5
Long-term Risk Management Liabilities	0.9	(0.8)	0.1
Total Liabilities	49.4	(45.8)	3.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.6)	$ 5.3	$ 4.7

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 14.9	$ (11.4)	$ 3.5
Long-term Risk Management Assets	1.1	(1.1)	—
Total Assets	16.0	(12.5)	3.5
Current Risk Management Liabilities	11.8	(11.5)	0.3
Long-term Risk Management Liabilities	1.9	(1.1)	0.8
Total Liabilities	13.7	(12.6)	1.1
Total MTM Derivative Contract Net Assets	$ 2.3	$ 0.1	$ 2.4

OPCo

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6

Current Risk Management Liabilities	6.4	—	6.4
Long-term Risk Management Liabilities	126.0	—	126.0
Total Liabilities	132.4	—	132.4
Total MTM Derivative Contract Net Liabilities	$ (131.8)	$ —	$ (131.8)

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.4	$ (0.2)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	0.4	(0.2)	0.2
Current Risk Management Liabilities	5.9	—	5.9
Long-term Risk Management Liabilities	113.1	—	113.1
Total Liabilities	119.0	—	119.0
Total MTM Derivative Contract Net Liabilities	$ (118.6)	$ (0.2)	$ (118.8)

PSO

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 6.6	$ (0.2)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.6	(0.2)	6.4
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets	$ 6.4	$ —	$ 6.4

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.9	$ (0.1)	$ 0.8
Long-term Risk Management Assets	—	—	—

Total Assets	0.9	(0.1)	0.8
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.9	$ (0.1)	$ 0.8

SWEPCo

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 7.0	$ (0.6)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	7.0	(0.6)	6.4
Current Risk Management Liabilities	0.8	(0.6)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.8	(0.6)	0.2
Total MTM Derivative Contract Net Assets	$ 6.2	$ —	$ 6.2

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 1.1	$ (0.2)	$ 0.9
Long-term Risk Management Assets	—	—	—
Total Assets	1.1	(0.2)	0.9
Current Risk Management Liabilities	0.4	(0.1)	0.3
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.4	(0.1)	0.3
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.7	$ (0.1)	$ 0.6

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The tables below present the Registrants' activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Year Ended December 31, 2017

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo

	(in millions)						
Vertically Integrated Utilities Revenues	$ 6.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	42.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.6	5.3	—	—	0.1
Purchased Electricity for Resale	5.6	—	2.0	0.6	—	—	—
Other Operation	0.8	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.7	0.2	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	(29.4)	—	—	(7.4)	(22.0)	—	0.3
Regulatory Liabilities (a)	109.4	0.1	40.4	15.9	—	24.8	24.3
Total Gain (Loss) on Risk Management Contracts	$ 136.0	$ 0.4	$ 43.2	$ 14.6	$ (21.8)	$ 25.0	$ 24.9

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2016

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 4.0	$ —	$ —	$ —	$ —	$ —	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—	—
Generation & Marketing Revenues	59.4	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.6)	4.1	0.1	—	—
Sales to AEP Affiliates	—	—	2.1	5.8	—	—	—
Purchased Electricity for Resale	6.6	—	3.5	0.3	—	—	—
Other Operation	(1.6)	(0.4)	(0.1)	(0.1)	(0.3)	(0.1)	(0.3)
Maintenance	(1.8)	(0.4)	(0.4)	(0.1)	(0.4)	(0.2)	(0.2)
Regulatory Assets (a)	(117.4)	0.8	0.6	3.1	(127.7)	0.4	5.2
Regulatory Liabilities (a)	79.1	0.4	51.4	13.9	(15.2)	6.5	15.7
Total Gain (Loss) on Risk Management Contracts	$ 28.4	$ 0.4	$ 56.5	$ 27.0	$ (143.5)	$ 6.6	$ 20.4

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2015

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 6.7	$ —	$ —	$ —	$ —	$ —	$ —
Transmission and Distribution Utilities Revenues	(4.3)	—	—	—	—	—	—
Generation & Marketing Revenues	54.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	1.1	3.3	(4.3)	—	—
Sales to AEP Affiliates	—	—	2.4	8.2	—	—	—
Purchased Electricity for Resale	6.4	—	2.0	0.4	—	—	—
Other Operation	(3.3)	(0.8)	(0.4)	(0.4)	(0.6)	(0.4)	(0.5)
Maintenance	(3.3)	(0.7)	(0.7)	(0.4)	(0.5)	(0.4)	(0.4)
Regulatory Assets (a)	(0.9)	0.4	3.4	(2.7)	—	0.6	(4.3)
Regulatory Liabilities (a)	30.2	—	28.7	7.5	(24.7)	4.4	15.1
Total Gain (Loss) on Risk Management Contracts	$ 86.4	$ (1.1)	$ 36.5	$ 15.9	$ (30.1)	$ 4.2	$ 9.9

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

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies (Applies to AEP)

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income. For 2017, 2016, and 2015, hedging gains and losses were immaterial.

For 2017, 2016 and 2015, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. The Registrants recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness would be recorded as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2017, 2016 and 2015, AEP applied cash flow hedging to outstanding power derivatives. During 2017, 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2017, 2016 and 2015, AEP applied cash flow hedging to outstanding interest rate derivatives. During 2017, 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items into qualifying foreign currency hedging relationships. During the years ended December 31, 2017 and 2016, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

During 2017, 2016 and 2015, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	December 31, 2017		December 31, 2016	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
Hedging Assets (a)	$ 22.0	$ —	$ 11.2	$ —
Hedging Liabilities (a)	65.5	—	46.7	—
AOCI Gain (Loss) Net of Tax	(28.4)	(13.0)	(23.1)	(15.7)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	5.5	(0.8)	4.3	(1.0)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

As of December 31, 2017 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 120 months.

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets

	December 31, 2017		December 31, 2016	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (4.5)	$ (0.9)	$ (5.4)	$ (0.9)
APCo	2.2	0.7	2.9	0.7
I&M	(10.7)	(1.3)	(12.0)	(1.3)
OPCo	1.9	1.1	3.0	1.1
PSO	2.6	0.8	3.4	0.8
SWEPCo	(6.0)	(1.4)	(7.4)	(1.4)

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk 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 Inc., S&P Global Inc. and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. A counterparty is required to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. AEP, APCo, I&M, PSO and SWEPCo have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had immaterial derivative contracts with collateral triggering events in a net liability position as of December 31, 2017 and 2016.

Cross-Default Triggers (Applies to AEP, APCo and I&M)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	AEP		
December 31,	**Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements**	**Amount of Cash Collateral Posted**	**Additional Settlement Liability if Cross Default Provision is Triggered**
		(in millions)	
2017	$ 243.6	$ 1.3	$ 223.1
2016	259.6	0.4	235.8

Amounts for APCo and I&M are immaterial for years ended December 31, 2017 and 2016.

11. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

Fair Value Measurements of Long-term Debt (Applies to all Registrants)

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

	December 31,			
	2017		2016	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP	$ 21,173.3	$ 23,649.6	$ 20,391.2 (a)	$ 22,211.9 (a)
AEP Texas	3,649.3	3,964.8	3,217.7	3,463.2
AEPTCo	2,550.4	2,782.9	1,932.0	1,984.3
APCo	3,980.1	4,782.6	4,033.9	4,613.2
I&M	2,745.1	3,014.7	2,471.4	2,661.6
OPCo	1,719.3	2,064.3	1,763.9	2,092.5
PSO	1,286.5	1,457.1	1,286.0	1,419.0
SWEPCo	2,441.9	2,645.9	2,679.1	2,814.3

(a) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet and has a fair value of $172 million. See the Assets and Liabilities Held for Sale section of Note 7 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include securities available for sale, including marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2017			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 220.1	$ —	$ —	$ 220.1
Fixed Income Securities – Mutual Funds (b)	104.3	—	(1.4)	102.9
Equity Securities – Mutual Funds	17.0	19.7	—	36.7
Total Other Temporary Investments	$ 341.4	$ 19.7	$ (1.4)	$ 359.7

Other Temporary Investments	December 31, 2016 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 211.7	$ —	$ —	$ 211.7
Fixed Income Securities – Mutual Funds (b)	92.7	—	(1.0)	91.7
Equity Securities – Mutual Funds	14.4	13.9	—	28.3
Total Other Temporary Investments	$ 318.8	$ 13.9	$ (1.0)	$ 331.7

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Years Ended December 31, 2017	2016	2015
	(in millions)		
Proceeds from Investment Sales	$ —	$ —	$ —
Purchases of Investments	14.2	2.3	10.7
Gross Realized Gains on Investment Sales	—	—	—
Gross Realized Losses on Investment Sales	—	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the years ended December 31, 2017, 2016 and 2015, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments:

	December 31, 2017 Fair Value	2017 Gross Unrealized Gains	2017 Other-Than-Temporary Impairments	2016 Fair Value	2016 Gross Unrealized Gains	2016 Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 17.2	$ —	$ —	$ 18.7	$ —	$ —
Fixed Income Securities:						
United States Government	981.2	29.7	(3.6)	785.4	27.1	(5.5)
Corporate Debt	58.7	3.8	(1.2)	60.9	2.3	(1.4)
State and Local Government	8.8	0.8	(0.2)	121.1	0.4	(0.7)
Subtotal Fixed Income Securities	1,048.7	34.3	(5.0)	967.4	29.8	(7.6)
Equity Securities – Domestic	1,461.7	868.2	(75.5)	1,270.1	677.9	(79.6)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,527.6	$ 902.5	$ (80.5)	$ 2,256.2	$ 707.7	$ (87.2)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Proceeds from Investment Sales	$ 2,256.3	$ 2,957.7	$ 2,218.4
Purchases of Investments	2,300.5	3,000.0	2,272.0
Gross Realized Gains on Investment Sales	200.7	46.1	69.1
Gross Realized Losses on Investment Sales	146.0	24.4	53.0

The base cost of fixed income securities was $1 billion and $938 million as of December 31, 2017 and 2016, respectively. The base cost of equity securities was $594 million and $592 million as of December 31, 2017 and 2016, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2017 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 387.3
After 1 year through 5 years	287.4
After 5 years through 10 years	204.4
After 10 years	169.6
Total	$ 1,048.7

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Assets:					

Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 183.2	$ —	$ —	$ 36.9	$ 220.1
Fixed Income Securities – Mutual Funds	102.9	—	—	—	102.9
Equity Securities – Mutual Funds (b)	36.7	—	—	—	36.7
Total Other Temporary Investments	322.8	—	—	36.9	359.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.9	391.2	274.1	(285.4)	383.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	17.3	4.7	—	22.0
Fair Value Hedges	—	2.5	—	—	2.5
Total Risk Management Assets	3.9	411.0	278.8	(285.4)	408.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$ 1,795.9	$ 1,459.7	$ 278.8	$ (238.8)	$ 3,295.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 5.1	$ 392.5	$ 196.9	$ (285.0)	$ 309.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	23.9	41.6	—	65.5
Fair Value Hedges	—	8.6	—	—	8.6
Total Risk Management Liabilities	$ 5.1	$ 425.0	$ 238.5	$ (285.0)	$ 383.6

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 8.7	$ —	$ —	$ 201.8	$ 210.5
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	173.8	5.1	—	32.8	211.7

Fixed Income Securities – Mutual Funds	91.7	—	—	—	91.7
Equity Securities – Mutual Funds (b)	28.3	—	—	—	28.3
Total Other Temporary Investments	293.8	5.1	—	32.8	331.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	6.0	379.9	192.2	(205.7)	372.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	16.8	1.7	(7.3)	11.2
Total Risk Management Assets	6.0	396.7	193.9	(213.0)	383.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities – Domestic (b)	1,270.1	—	—	—	1,270.1
Total Spent Nuclear Fuel and Decommissioning Trusts	1,277.4	967.4	—	11.4	2,256.2
Total Assets	$ 1,585.9	$ 1,369.2	$ 193.9	$ 33.0	$ 3,182.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 8.2	$ 352.0	$ 166.7	$ (205.4)	$ 321.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	29.3	24.7	(7.3)	46.7
Fair Value Hedges	—	1.4	—	—	1.4
Total Risk Management Liabilities	$ 8.2	$ 382.7	$ 191.4	$ (212.7)	$ 369.6

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 155.2	$ —	$ —	$ —	$ 155.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.5	—	—	0.5
Total Assets	$ 155.2	$ 0.5	$ —	$ —	$ 155.7

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 146.3	$ —	$ —	$ —	$ 146.3
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.4	—	(0.2)	0.2
Total Assets	$ 146.3	$ 0.4	$ —	$ (0.2)	$ 146.5

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 16.3	$ —	$ —	$ —	$ 16.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	52.5	25.1	(51.6)	26.0
Total Assets	$ 16.3	$ 52.5	$ 25.1	$ (51.6)	$ 42.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 51.2	$ 0.4	$ (50.1)	$ 1.5

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding (a)	$ 15.8	$ —	$ —	$ 0.1	$ 15.9
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	20.5	3.9	(21.8)	2.6
Total Assets	$ 15.8	$ 20.5	$ 3.9	$ (21.7)	$ 18.5

Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 20.7	$ 2.5	$ (22.0)	$ 1.2

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 39.4	$ 9.1	$ (40.2)	$ 8.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$ 1,469.2	$ 1,088.1	$ 9.1	$ (30.5)	$ 2,535.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 47.6	$ 1.5	$ (45.5)	$ 3.6

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 12.8	$ 3.0	$ (12.3)	$ 3.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4

Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities – Domestic (b)	1,270.1	—	—	—	1,270.1
Total Spent Nuclear Fuel and Decommissioning Trusts	1,277.4	967.4	—	11.4	2,256.2
Total Assets	$ 1,277.4	$ 980.2	$ 3.0	$ (0.9)	$ 2,259.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 13.3	$ 0.2	$ (12.4)	$ 1.1

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.6	$ —	$ —	$ 0.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 132.4	$ —	$ 132.4

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding (a)	$ —	$ —	$ —	$ 27.2	$ 27.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.4	—	(0.2)	0.2
Total Assets	$ —	$ 0.4	$ —	$ 27.0	$ 27.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 119.0	$ —	$ 119.0

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 6.4	$ (0.2)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.2	$ (0.2)	$ —

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 0.7	$ (0.1)	$ 0.8

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 6.7	$ (0.6)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.8	$ (0.6)	$ 0.2

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total

Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 8.7	$ —	$ —	$ 1.6	$ 10.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.3	0.8	(0.2)	0.9
Total Assets	$ 8.7	$ 0.3	$ 0.8	$ 1.4	$ 11.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 0.1	$ (0.1)	$ 0.3

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) The December 31, 2017 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(1) million in periods 2018; Level 2 matures $(3) million in 2018 and $2 million in periods 2022-2023; Level 3 matures $59 million in 2018, $33 million in periods 2019-2021, $14 million in periods 2022-2023 and $(29) million in periods 2024-2032. Risk management commodity contracts are substantially comprised of power contracts.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(f) The December 31, 2016 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(2) million in periods 2018-2020; Level 2 matures $20 million in 2017, $4 million in periods 2018-2020, $3 million in periods 2021-2022 and $1 million in periods 2023-2032; Level 3 matures $17 million in 2017, $28 million in periods 2018-2020, $11 million in periods 2021-2022 and $(31) million in periods 2023-2032. Risk management commodity contracts are substantially comprised of power contracts.
(g) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2017, 2016 and 2015.

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

Year Ended December 31, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	37.3	17.2	4.0	(1.4)	3.1	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	33.6	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(18.8)	—	—	—	—	—
Settlements	(50.6)	(18.9)	(7.1)	7.4	(3.8)	(6.8)
Transfers into Level 3 (d) (e)	16.2	—	—	—	—	—
Transfers out of Level 3 (e)	(10.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	30.2	25.0	7.9	(19.4)	6.2	6.0
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9

Year Ended December 31, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2015	$ 146.9	$ 11.7	$ 4.3	$ 15.9	$ 0.6	$ 0.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	42.8	25.6	7.1	(3.0)	(1.0)	7.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	26.1	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(23.0)	—	—	—	—	—
Settlements	(71.4)	(37.5)	(11.1)	6.2	0.4	(8.4)
Transfers into Level 3 (d) (e)	13.3	—	—	—	—	—
Transfers out of Level 3 (e)	(2.6)	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(129.6)	1.5	2.4	(138.1)	0.7	0.6
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7

Year Ended December 31, 2015	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2014	$ 150.8	$ 15.8	$ 14.7	$ 48.4	$ (0.3)	$ (0.5)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	13.5	2.1	0.2	0.5	(0.2)	9.2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	53.7	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(4.9)	—	—	—	—	—
Settlements	(63.0)	(17.2)	(14.2)	(6.7)	0.6	(8.7)
Transfers into Level 3 (d) (e)	28.7	—	—	—	—	—
Transfers out of Level 3 (e)	(18.9)	1.2	0.8	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(13.0)	9.8	2.8	(26.3)	0.5	0.8
Balance as of December 31, 2015	$ 146.9	$ 11.7	$ 4.3	$ 15.9	$ 0.6	$ 0.8

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
December 31, 2017

AEP

	Significant	Input/Range

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 225.1	$ 233.7	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 263.00	$ 36.32
				Counterparty Credit Risk (b)	8	456	180
Natural Gas Contracts	—	0.2	Discounted Cash Flow	Forward Market Price (c)	2.37	2.96	2.62
FTRs	53.7	4.6	Discounted Cash Flow	Forward Market Price (a)	(55.62)	54.88	0.41
Total	$ 278.8	$ 238.5					

Significant Unobservable Inputs
December 31, 2016

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 183.8	$ 187.1	Discounted Cash Flow	Forward Market Price (a)	$ 6.51	$ 86.59	$ 39.40
				Counterparty Credit Risk (b)	35	824	391
FTRs	10.1	4.3	Discounted Cash Flow	Forward Market Price (a)	(7.99)	8.91	0.86
Total	$ 193.9	$ 191.4					

Significant Unobservable Inputs
December 31, 2017

APCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.8	$ 0.4	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	24.3	—	Discounted Cash Flow	Forward Market Price	(0.36)	7.15	1.62
Total	$ 25.1	$ 0.4					

Significant Unobservable Inputs
December 31, 2016

APCo

Significant **Input/Range**

	Fair Value		Valuation	Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$ 0.4	$ 0.4	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	3.5	2.1	Discounted Cash Flow	Forward Market Price	(0.23)	8.91	2.37
Total	$ 3.9	$ 2.5					

Significant Unobservable Inputs
December 31, 2017

I&M

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	8.6	1.2	Discounted Cash Flow	Forward Market Price	(0.36)	5.75	0.86
Total	$ 9.1	$ 1.5					

Significant Unobservable Inputs
December 31, 2016

I&M

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.3	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	2.7	—	Discounted Cash Flow	Forward Market Price	(7.90)	8.91	1.32
Total	$ 3.0	$ 0.2					

Significant Unobservable Inputs
December 31, 2017

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 132.4	Discounted Cash Flow	Forward Market Price (a)	$ 30.52	$ 170.43	$ 44.62

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Low	High	Weighted Average
				Counterparty Credit Risk (b)	8	190	136
Total	$ —	$ 132.4					

Significant Unobservable Inputs
December 31, 2016

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 119.0	Discounted Cash Flow	Forward Market Price (a)	$ 30.14	$ 71.85	$ 47.45
				Counterparty Credit Risk (b)	47	340	272
Total	$ —	$ 119.0					

Significant Unobservable Inputs
December 31, 2017

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 6.4	$ 0.2	Discounted Cash Flow	Forward Market Price	$ (6.62)	$ 1.41	$ (0.76)

Significant Unobservable Inputs
December 31, 2016

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.7	$ —	Discounted Cash Flow	Forward Market Price	$ (7.99)	$ 1.03	$ (0.36)

Significant Unobservable Inputs
December 31, 2017

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						

Natural Gas Contracts	$ —	$ 0.2	Discounted Cash Flow	Forward Market Price (c)	$ 2.37	$ 2.96	$ 2.62
FTRs	6.7	0.6	Discounted Cash Flow	Forward Market Price (a)	(6.62)	1.41	(0.76)
Total	$ 6.7	$ 0.8					

Significant Unobservable Inputs
December 31, 2016

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.8	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (7.99)	$ 1.03	$ (0.36)

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

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of December 31, 2017 and 2016:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)
Counterparty Credit Risk	Loss	Increase (Decrease)	Higher (Lower)
Counterparty Credit Risk	Gain	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Federal Tax Reform

In December 2017, legislation referred to as Tax Reform was signed into law. The majority of the provisions in the new legislation are effective for taxable years beginning after December 31, 2017. Tax Reform includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and also includes provisions specific to regulated public utilities. The more significant changes that affect the Registrants include the reduction in the corporate federal income tax rate from 35% to 21%, and several technical provisions including, among others, limiting the utilization of net operating losses arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, eliminate bonus depreciation for certain property acquired after September

27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

Provisional Amounts

Given the significance of the legislative changes resulting from Tax Reform, the timing of its enactment, and the widespread applicability to registrants, the SEC staff recognized the potential challenges faced by registrants when reflecting the effects of Tax Reform in their 2017 financial statements. Accordingly, in order to address potential uncertainty or diversity of views in practice regarding the application of the accounting guidance for "Income Taxes" in situations where a registrant does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for "Income Taxes" for certain tax effects of Tax Reform for the reporting period in which the legislation was enacted, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. For such areas of analysis that are incomplete, SAB 118 provides for up to a one year period in which to complete the required analyses and accounting required by the accounting guidance for "Income Taxes," referred to as the measurement period.

SAB 118 describes three categories associated with a registrant's status of accounting for Tax Reform during the measurement period: (a) a registrant is complete with its accounting for certain effects of Tax Reform, (b) a registrant's accounting is incomplete but is able to determine a reasonable estimate for certain effects of Tax Reform and records that estimate as a provisional amount, or (c) the accounting is incomplete and a registrant is not able to determine a reasonable estimate and therefore continues to apply existing accounting guidance for income taxes, based on the provisions of the tax laws that were in effect immediately prior to the enactment of the Tax Reform legislation. For items in which the accounting assessment is complete or a reasonable estimate can be made, a registrant must reflect the income tax effects of Tax Reform for those items in its financial statements that include the enactment of the Tax Reform legislation. SAB 118 also requires certain disclosures to provide information about the material financial reporting impacts, if any, due to Tax Reform for which the accounting is not complete. Subsequent disclosures in future reporting periods in which the accounting is completed are also a requirement of the guidance.

The Registrants have made a reasonable estimate for the measurement and accounting of the effects of Tax Reform which have been reflected in the December 31, 2017 financial statements as provisional amounts based on information available. While the Registrants were able to make reasonable estimates of the impact of Tax Reform, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative temporary differences or as a result of additional guidance or technical corrections that may be issued by the IRS that may impact management's interpretation and assumptions utilized. The Registrants expect to complete the analysis of the provisional items during the second half of 2018.

The recorded provisional amounts include $154 million of excess accumulated deferred income taxes (Excess ADIT) related to AEP Transmission Holdco's equity investment in ETT. ETT is a three-member limited liability company that is a partnership for federal income tax purposes. The rates ETT is permitted to charge its customers are regulated by the PUCT. Those rates contemplate deferred taxes; however, the income tax effects of ETT's activities are the responsibility of its members, including AEP Transmission Holdco. As a result, AEP's proportionate share of the Excess ADIT related to ETT is reflected by AEP Transmission Holdco and is reflected in AEP's December 31, 2017 balance sheet as a reduction in Deferred Income Taxes with a corresponding increase in Regulatory Liabilities and Deferred Investment Tax Credits. AEP's accounting for Excess ADIT related to partnerships is provisional as it may be subject to further interpretation of Tax Reform.

Impact of Tax Reform on the Financial Statements

Changes in the Code due to Tax Reform had a material impact on the Registrants' 2017 financial statements. In accordance with the accounting guidance for "Income Taxes", the effect of a change in tax law must be recognized at the date of enactment. The accounting guidance for "Income Taxes" also requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences will be realized or settled. As a result, the Registrants' deferred tax assets and liabilities were re-measured using the newly enacted tax rate of 21% in December 2017. This re-measurement resulted in a significant reduction in the Registrants' net accumulated deferred income tax liability. With respect to the Registrants' regulated operations, the reduction of the net accumulated deferred income tax liability was primarily offset by a corresponding decrease in income tax related regulatory assets and an increase in income tax related regulatory liabilities because the benefit of the lower federal tax rate is expected to be provided to customers. However, when the underlying asset or liability giving rise to the temporary difference was not previously contemplated in regulated rates, the re-measurement of the deferred taxes on those assets or liabilities was recorded as an adjustment to income tax expense. For the Registrants' unregulated operations, the re-measurement of deferred taxes arising from those operations was recorded as an adjustment to income tax expense.

The following tables provide a summary of the impact of Tax Reform on the Registrants' 2017 financial statements.

Year Ended December 31, 2017	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Decrease in Deferred Income Tax Liabilities	$ 6,101.1	$ 807.1	$ 558.6	$ 1,296.4	$ 808.7	$ 743.1	$ 538.6	$ 782.9

This decrease in deferred income tax liabilities resulted in an increase in income tax related regulatory liabilities, a decrease in income tax related regulatory assets and an adjustment to income tax expense as shown in the table below.

Year Ended December 31, 2017	**AEP (c)**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Increase (Decrease) in Income Tax Expense (a)	$ (16.5)	$ (117.4) (b)	$ 0.6	$ 5.7	$ 2.3	$ (14.3) (b)	$ 2.8	$ 0.7
Decrease in Regulatory Assets	470.2	12.1	66.9	129.1	85.3	62.7	8.3	69.8
Increase in Regulatory Liabilities	5,614.4	677.6	492.3	1,173.0	725.7	666.1	533.1	713.8

(a) In 2017, in contemplation of corporate federal tax reform, the Registrants adopted a method under Internal Revenue Section 162 for deducting repair and maintenance costs associated with transmission and distribution property. This change resulted in a decrease in state income tax expense of approximately $10 million that has been excluded from the tables above.

(b) AEP Texas and OPCo recorded favorable adjustments to income tax expense of approximately $113 million and $16 million related to previously owned deregulated generation assets and certain deferred fuel amounts, respectively.

(c) The effect of Tax Reform on AEP's other business operations (other than the Registrant Subsidiaries), which primarily include unregulated activities in the Generation & Marketing segment, transmission operations reflected in the AEP Transmission Holdco segment and activities recorded in Corporate and Other, increased income tax expense for the year-ended December 31, 2017 by approximately $103 million.

Regulatory Treatment

As a result of Tax Reform, the Registrants recognized a regulatory liability for approximately $4.4 billion of Excess ADIT, as well as an incremental liability of $1.2 billion to reflect the $4.4 billion Excess ADIT on a pre-tax basis, which is presented in Regulatory Liabilities and Deferred Income Taxes on the balance sheets. The Excess ADIT is reflected on a pretax basis to appropriately contemplate future tax consequences in the periods when the regulatory liability is settled. Approximately $3.2 billion of the Excess ADIT relates to temporary differences associated with depreciable property. The Tax Reform legislation includes certain rate normalization requirements that stipulate how the portion of the total Excess ADIT that is related to certain depreciable property must be returned to customers. Specifically, for AEP's regulated public utilities that are subject to those rate normalization requirements, Excess ADIT resulting from the reduction of the corporate tax rate with respect to prior depreciation or recovery deductions on property will be normalized using the average rate assumption method. As a result, once the amortization of this Excess ADIT is reflected in rates, customers will receive the benefits over the remaining weighted average useful life of the applicable property.

For the remaining $1.2 billion of Excess ADIT, the Registrants expect to continue working with each state regulatory commission to determine the appropriate mechanism and time period over which to provide the benefits of Tax Reform to customers.

The Registrants expect the mechanism and time period to provide the benefits of Tax Reform to customers will vary by jurisdiction and will reduce future cash flows, may impact financial condition, but is not expected to have a material impact on future net income.

State Regulatory Matters

Various state utility commissions have recently issued orders requiring public utilities, including the Registrants, to record regulatory liabilities to reflect the corporate federal income taxes currently collected in utility rates in excess of the enacted corporate federal income tax rate of 21% beginning January 1, 2018. See Note 4 - Rate Matters for additional information regarding state utility commission orders received impacting the Registrant Subsidiaries.

Income Tax Expense (Credit)

The details of the Registrants' income tax expense (credit) before discontinued operations as reported are as follows:

Year Ended December 31, 2017	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Federal:								
Current	$ (4.0)	$ (85.7)	$ (127.5)	$ 15.3	$ (106.5)	$ 11.2	$ (77.1)	$ (30.1)
Deferred	856.6	63.3	256.0	166.9	202.1	141.3	122.7	84.8
Deferred Investment Tax Credits	48.6	(1.6)	—	(0.1)	(4.7)	—	(1.6)	(1.4)
Total Federal	901.2	(24.0)	128.5	182.1	90.9	152.5	44.0	53.3
State and Local:								
Current	16.0	0.6	1.9	(1.4)	(8.1)	0.2	(0.2)	(0.9)
Deferred	44.9	—	16.8	4.6	(1.4)	6.6	2.0	(4.3)
Deferred Investment Tax Credits	7.6	—	—	—	—	—	4.3	—
Total State and Local	68.5	0.6	18.7	3.2	(9.5)	6.8	6.1	(5.2)
Income Tax Expense (Credit) Before Discontinued Operations	$ 969.7	$ (23.4)	$ 147.2	$ 185.3	$ 81.4	$ 159.3	$ 50.1	$ 48.1

Year Ended December 31, 2016	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Federal:								
Current	$ (30.7)	$ 40.9	$ (129.4)	$ 64.1	$ (44.8)	$ 178.8	$ (28.0)	$ (96.7)
Deferred	(28.8)	29.9	205.9	125.8	104.9	(40.8)	77.2	172.6
Deferred Investment Tax Credits	17.6	(1.7)	—	(0.1)	3.8	—	(1.4)	(1.2)
Total Federal	(41.9)	69.1	76.5	189.8	63.9	138.0	47.8	74.7
State and Local:								
Current	(10.5)	(8.8)	0.4	4.4	3.4	4.2	(1.9)	(12.6)
Deferred	(21.2)	(0.4)	17.2	4.9	0.2	1.6	5.3	(10.0)
Deferred Investment Tax Credits	(0.1)	—	—	—	—	—	3.2	—

Total State and Local	(31.8)	(9.2)	17.6	9.3	3.6	5.8	6.6	(22.6)
Income Tax Expense (Credit) Before Discontinued Operations	$ (73.7)	$ 59.9	$ 94.1	$ 199.1	$ 67.5	$ 143.8	$ 54.4	$ 52.1

Year Ended December 31, 2015	**AEP**	**AEP Texas**	**AEPTCo**
		(in millions)	
Federal:			
Current	$ 107.3	$ 61.4	$ (126.3)
Deferred	774.8	(7.1)	171.3
Deferred Investment Tax Credits	—	(1.7)	—
Total Federal	882.1	52.6	45.0
State and Local:			
Current	14.5	5.6	3.1
Deferred	23.0	—	11.9
Total State and Local	37.5	5.6	15.0
Income Tax Expense Before Discontinued Operations	$ 919.6	$ 58.2	$ 60.0

Year Ended December 31, 2015	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in millions)		
Income Tax Expense (Credit):					
Current	$ (32.9)	$ 5.2	$ 89.0	$ (6.4)	$ 44.3
Deferred	227.5	94.2	37.6	58.3	41.9
Deferred Investment Tax Credits	(0.3)	(3.3)	(0.1)	(0.6)	(1.4)
Income Tax Expense	$ 194.3	$ 96.1	$ 126.5	$ 51.3	$ 84.8

The following is a reconciliation for each Registrant of the difference between the amounts of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

AEP	**Years Ended December 31,**		
	2017	**2016**	**2015**
		(in millions)	
Net Income	$ 1,928.9	$ 618.0	$ 2,052.3
Discontinued Operations (Net of Income Tax of $0, $0 and $6.2 in 2017, 2016 and 2015, Respectively)	—	2.5	(283.7)
Income Tax Expense (Credit) Before Discontinued Operations	969.7	(73.7)	919.6
Pretax Income	$ 2,898.6	$ 546.8	$ 2,688.2
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 1,014.5	$ 191.4	$ 940.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	60.2	41.7	53.6
Investment Tax Credit Amortization	(18.8)	(12.3)	(11.6)
State and Local Income Taxes, Net	54.7	(20.7)	24.4
Removal Costs	(32.7)	(39.8)	(28.8)

	2017	2016	2015
AFUDC	(37.4)	(44.8)	(51.6)
Valuation Allowance	(1.8)	(128.3)	17.2
U.K. Windfall Tax	—	(12.9)	—
Tax Reform Adjustments	(26.7)	—	—
Tax Adjustments	(35.8)	(43.9)	(20.1)
Other	(6.5)	(4.1)	(4.4)
Income Tax Expense (Credit) Before Discontinued Operations	$ 969.7	$ (73.7)	$ 919.6
Effective Income Tax Rate	33.5 %	(13.5) %	34.2 %

AEP Texas	**Years Ended December 31,**		
	2017	**2016**	**2015**
		(in millions)	
Net Income	$ 310.5	$ 146.6	$ 120.3
Discontinued Operations (Net of Income Tax of $0, $27.6 and $1.8 in 2017, 2016 and 2015, Respectively)	—	48.8	1.4
Income Tax Expense	(23.4)	59.9	58.2
Pretax Income	$ 287.1	$ 255.3	$ 179.9
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 100.5	$ 89.4	$ 63.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	0.7	0.5	0.5
Investment Tax Credit Amortization	(1.6)	(1.7)	(1.7)
State and Local Income Taxes, Net	0.4	(6.0)	3.6
Parent Company Loss Benefit	—	(2.5)	(3.1)
Tax Reform Adjustments	(117.4)	—	—
Tax Adjustments	(4.2)	(4.9)	(1.6)
U.K. Windfall Tax	—	(12.9)	—
Other	(1.8)	(2.0)	(2.5)
Income Tax Expense (Credit) Before Discontinued Operations	$ (23.4)	$ 59.9	$ 58.2
Effective Income Tax Rate	(8.2) %	23.5 %	32.4 %

AEPTCo	**Years Ended December 31,**		
	2017	**2016**	**2015**
		(in millions)	
Net Income	$ 286.1	$ 192.7	$ 132.9
Income Tax Expense	147.2	94.1	60.0
Pretax Income	$ 433.3	$ 286.8	$ 192.9
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 151.7	$ 100.4	$ 67.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
AFUDC	(18.3)	(18.3)	(18.6)
State and Local Income Taxes, Net	12.2	11.4	9.8
Tax Reform Adjustments	0.6	—	—
Other	1.0	0.6	1.3

	2017	2016	2015
Income Tax Expense	$ 147.2	$ 94.1	$ 60.0
Effective Income Tax Rate	34.0 %	32.8 %	31.1 %

APCo

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net Income	$ 331.3	$ 369.1	$ 340.6
Income Tax Expense	185.3	199.1	194.3
Pretax Income	$ 516.6	$ 568.2	$ 534.9
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 180.8	$ 198.9	$ 187.2
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	18.0	19.3	19.8
Investment Tax Credit Amortization	(0.1)	(0.1)	(0.3)
State and Local Income Taxes, Net	3.5	6.0	7.2
Removal Costs	(12.4)	(12.0)	(9.9)
AFUDC	(5.0)	(6.1)	(7.0)
Valuation Allowance	—	(1.7)	1.7
Tax Reform Adjustments	4.3	—	—
Other	(3.8)	(5.2)	(4.4)
Income Tax Expense	$ 185.3	$ 199.1	$ 194.3
Effective Income Tax Rate	35.9 %	35.0 %	36.3 %

I&M

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net Income	$ 186.7	$ 239.9	$ 204.8
Income Tax Expense	81.4	67.5	96.1
Pretax Income	$ 268.1	$ 307.4	$ 300.9
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 93.8	$ 107.6	$ 105.3
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	11.4	6.7	9.5
Investment Tax Credit Amortization	(4.7)	(4.7)	(3.3)
State and Local Income Taxes, Net	(1.0)	2.4	5.8
Removal Costs	(13.3)	(21.3)	(12.6)
AFUDC	(5.6)	(7.3)	(6.2)
Tax Adjustments	2.7	(14.2)	(4.2)
Tax Reform Adjustments	(2.9)	—	—
Other	1.0	(1.7)	1.8
Income Tax Expense	$ 81.4	$ 67.5	$ 96.1
Effective Income Tax Rate	30.4 %	22.0 %	31.9 %

OPCo

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net Income	$ 323.9	$ 282.2	$ 232.7
Income Tax Expense	159.3	143.8	126.5
Pretax Income	$ 483.2	$ 426.0	$ 359.2
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 169.1	$ 149.1	$ 125.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	7.6	7.1	8.2
Investment Tax Credit Amortization	—	—	(0.1)
State and Local Income Taxes, Net	4.4	3.8	0.7
Tax Reform Adjustments	(14.4)	—	—
Other	(7.4)	(16.2)	(8.0)
Income Tax Expense	$ 159.3	$ 143.8	$ 126.5
Effective Income Tax Rate	33.0 %	33.8 %	35.2 %

PSO

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net Income	$ 72.0	$ 100.0	$ 92.5
Income Tax Expense	50.1	54.4	51.3
Pretax Income	$ 122.1	$ 154.4	$ 143.8
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 42.7	$ 54.0	$ 50.3
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	0.3	0.8	0.5
Investment Tax Credit Amortization	(1.6)	(1.4)	(1.8)
State and Local Income Taxes, Net	4.0	4.2	5.1
AFUDC	(0.2)	(2.2)	(3.1)
Tax Reform Adjustments	2.8	—	—
Other	2.1	(1.0)	0.3
Income Tax Expense	$ 50.1	$ 54.4	$ 51.3
Effective Income Tax Rate	41.0 %	35.2 %	35.7 %

SWEPCo

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net Income	$ 137.5	$ 169.7	$ 196.0
Income Tax Expense	48.1	52.1	84.8
Pretax Income	$ 185.6	$ 221.8	$ 280.8
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 65.0	$ 77.6	$ 98.3

Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.9	3.2	3.1
Depletion	(5.7)	(5.5)	(5.5)
Investment Tax Credit Amortization	(1.4)	(1.2)	(1.4)
State and Local Income Taxes, Net	(2.3)	(14.7)	4.8
AFUDC	(0.9)	(3.9)	(9.2)
Tax Adjustments	(9.9)	(0.9)	(3.9)
Tax Reform Adjustments	(0.4)	—	—
Other	1.8	(2.5)	(1.4)
Income Tax Expense	$ 48.1	$ 52.1	$ 84.8
Effective Income Tax Rate	25.9 %	23.5 %	30.2 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

AEP	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 3,504.6	$ 2,753.0
Deferred Tax Liabilities	(10,318.5)	(14,637.4)
Net Deferred Tax Liabilities	$ (6,813.9)	$ (11,884.4)
Property Related Temporary Differences	$ (5,680.6)	$ (8,758.1)
Amounts Due to/(from) Customers for Future Federal Income Taxes	1,064.8	(292.2)
Deferred State Income Taxes	(1,124.4)	(976.6)
Securitized Assets	(257.7)	(535.6)
Regulatory Assets	(500.3)	(896.9)
Deferred Income Taxes on Other Comprehensive Loss	25.7	88.7
Accrued Nuclear Decommissioning	(457.0)	(666.8)
Net Operating Loss Carryforward	86.6	101.2
Tax Credit Carryforward	174.7	45.1
Investment in Partnership	(222.0)	(349.6)
Valuation Allowance	—	(1.8)
All Other, Net	76.3	358.2
Net Deferred Tax Liabilities	$ (6,813.9)	$ (11,884.4)

AEP Texas	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 221.0	$ 135.8
Deferred Tax Liabilities	(1,134.1)	(1,667.5)
Net Deferred Tax Liabilities	$ (913.1)	$ (1,531.7)
Property Related Temporary Differences	$ (791.5)	$ (1,056.1)
Amounts Due to/(from) Customers for Future Federal Income Taxes	140.9	(5.7)

Deferred State Income Taxes	(27.5)	(24.2)
Regulatory Assets	(36.4)	(61.3)
Securitized Transition Assets	(190.5)	(407.0)
Deferred Income Taxes on Other Comprehensive Loss	4.1	8.0
Deferred Revenues	10.9	18.0
All Other, Net	(23.1)	(3.4)
Net Deferred Tax Liabilities	$ (913.1)	$ (1,531.7)

AEPTCo	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 162.7	$ 61.4
Deferred Tax Liabilities	(764.4)	(923.5)
Net Deferred Tax Liabilities	$ (601.7)	$ (862.1)
Property Related Temporary Differences	$ (654.7)	$ (825.6)
Amounts Due to/(from) Customers for Future Federal Income Taxes	89.7	(37.2)
Deferred State Income Taxes	(77.4)	(55.6)
Deferred Federal Income Taxes on Deferred State Income Taxes	16.3	19.5
Net Operating Loss Carryforward	16.8	33.3
Valuation Allowance	—	0.1
Tax Credit Carryforward	0.3	—
All Other, Net	7.3	3.4
Net Deferred Tax Liabilities	$ (601.7)	$ (862.1)

APCo	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 614.4	$ 413.5
Deferred Tax Liabilities	(2,180.1)	(3,085.8)
Net Deferred Tax Liabilities	$ (1,565.7)	$ (2,672.3)
Property Related Temporary Differences	$ (1,308.2)	$ (2,031.9)
Amounts Due to/(from) Customers for Future Federal Income Taxes	228.0	(73.1)
Deferred State Income Taxes	(335.7)	(319.3)
Regulatory Assets	(83.9)	(159.9)
Securitized Assets	(59.3)	(106.9)
Deferred Income Taxes on Other Comprehensive Loss	(0.4)	4.5
Tax Credit Carryforward	16.6	11.7
All Other, Net	(22.8)	2.6
Net Deferred Tax Liabilities	$ (1,565.7)	$ (2,672.3)

I&M	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 1,096.4	$ 912.9

Deferred Tax Liabilities	(2,050.2)	(2,440.3)
Net Deferred Tax Liabilities	$ (953.8)	$ (1,527.4)

Property Related Temporary Differences	$ (403.0)	$ (579.4)
Amounts Due to/(from) Customers for Future Federal Income Taxes	137.6	(50.4)
Deferred State Income Taxes	(180.6)	(158.7)
Deferred Income Taxes on Other Comprehensive Loss	3.9	8.8
Accrued Nuclear Decommissioning	(457.0)	(666.8)
Regulatory Assets	(43.8)	(81.0)
Net Operating Loss Carryforward	1.6	7.1
All Other, Net	(12.5)	(7.0)
Net Deferred Tax Liabilities	$ (953.8)	$ (1,527.4)

OPCo	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 286.0	$ 232.4
Deferred Tax Liabilities	(1,048.9)	(1,578.5)
Net Deferred Tax Liabilities	$ (762.9)	$ (1,346.1)
Property Related Temporary Differences	$ (761.2)	$ (1,090.8)
Amounts Due to/(from) Customers for Future Federal Income Taxes	127.3	(43.6)
Deferred State Income Taxes	(41.7)	(34.6)
Regulatory Assets	(107.7)	(174.1)
Deferred Income Taxes on Other Comprehensive Loss	(0.6)	(1.6)
Deferred Fuel and Purchased Power	(24.5)	(117.6)
All Other, Net	45.5	116.2
Net Deferred Tax Liabilities	$ (762.9)	$ (1,346.1)

PSO	**December 31,**	
	2017	**2016**
	(in millions)	
Deferred Tax Assets	$ 269.2	$ 153.8
Deferred Tax Liabilities	(911.2)	(1,212.6)
Net Deferred Tax Liabilities	$ (642.0)	$ (1,058.8)
Property Related Temporary Differences	$ (623.8)	$ (927.3)
Amounts Due to/(from) Customers for Future Federal Income Taxes	111.6	(3.2)
Deferred State Income Taxes	(142.7)	(128.5)
Regulatory Assets	(34.4)	(67.6)
Deferred Income Taxes on Other Comprehensive Loss	(0.8)	(1.8)
Deferred Federal Income Taxes on Deferred State Income Taxes	33.5	50.6
Net Operating Loss Carryforward	23.1	16.5
Tax Credit Carryforward	0.7	—

All Other, Net		(9.2)		2.5
Net Deferred Tax Liabilities	$	(642.0)	$	(1,058.8)

SWEPCo	**December 31,**			
	2017		**2016**	
	(in millions)			
Deferred Tax Assets	$	349.4	$	230.5
Deferred Tax Liabilities		(1,267.1)		(1,837.4)
Net Deferred Tax Liabilities	$	(917.7)	$	(1,606.9)
Property Related Temporary Differences	$	(908.8)	$	(1,445.2)
Amounts Due to/(from) Customers for Future Federal Income Taxes		135.8		(48.2)
Deferred State Income Taxes		(189.2)		(175.1)
Regulatory Assets		(30.8)		(40.7)
Deferred Income Taxes on Other Comprehensive Loss		1.3		5.1
Capital/Impairment Loss - Turk Plant		17.4		20.3
Net Operating Loss Carryforward		38.7		40.3
Tax Credit Carryforward		0.8		0.1
All Other, Net		17.1		36.5
Net Deferred Tax Liabilities	$	(917.7)	$	(1,606.9)

AEP System Tax Allocation Agreement

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

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective negative evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions.

On the basis of this evaluation, AEP recorded a valuation allowance of $17 million in the fourth quarter of 2015 related to the expected expiration of charitable contribution carryforward deductions and realized capital losses. In the fourth quarter of 2015, AEP also reversed a valuation allowance originally recorded in the third quarter of 2015 of $156 million attributable to the unrealized capital loss associated with the excess tax basis of the stock over the book value of AEP's investment in the operations of AEPRO. With the sale of AEPRO in the fourth quarter of 2015, AEP recorded a valuation allowance of $48 million attributable to realized capital losses from the sale. As of December 31, 2015 there was a valuation allowance of $130 million recorded against AEP's deferred tax asset balance.

AEP recorded changes in the valuation allowance in the second quarter of 2016 related to the reversal of a $56 million unrealized capital loss where AEP effectively settled a 2011 audit issue with the IRS. AEP also recorded changes in the third quarter of 2016 by reducing the capital loss valuation allowance by $66 million to reflect the impact of the reclassification of certain assets held for sale and the filing of the 2015 federal income tax return. The sale of these assets held for sale are expected to result in a gain, the character of which will allow AEP to recognize the capital loss and allowed AEP to reverse substantially all of the remaining capital loss valuation allowance previously recorded. During the fourth quarter of 2016, AEP reversed $6 million of the valuation allowance associated with charitable contributions that expired at the end of the year. As of December 31, 2016 there was a valuation allowance of $2 million recorded against AEP's deferred tax asset balance related to an unrealized capital loss carryforward.

During 2017, the valuation allowance of $2 million recorded against AEP's deferred tax asset balance related to an unrealized capital loss carryforward was reversed, as the Company expects to have sufficient capital gains in the future to use this capital loss when realized. As of December 31, 2017, AEP and AEPTCo have recorded valuation allowances of $5 million and $2 million, respectively, against certain state and municipal net income tax operating loss carryforwards since future taxable income is not expected to be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011 through 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. To resolve the issue under consideration, AEP and subsidiaries

and the IRS exam team agreed to go to Appeals using Fast Track in December 2017. The issue is still waiting for resolution with Appeals. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrants accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns. AEP and subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. The Registrants are no longer subject to state or local income tax examinations by tax authorities for years before 2009.

Net Income Tax Operating Loss Carryforward

In 2017, Registrants specified in the table below recognized federal net income tax operating losses. The 2017 federal net income tax operating losses were driven primarily by bonus depreciation and deductions related to repair and maintenance costs associated with transmission and distribution property.

Company	**Year Ended December 31, 2017**
	(in millions)
AEP	$ 230.1
AEP Texas	261.8
AEPTCo	344.1

I&M	332.6
PSO	213.9
SWEPCo	87.6

Substantially all of the 2017 federal net income tax operating losses will be carried back to 2015. As of December 31, 2017, AEP had $4 million of remaining unrealized federal net operating loss carryforward tax benefits. Management anticipates future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2036. AEP, AEPTCo, I&M, PSO and SWEPCo also have state net income tax operating loss carryforwards as of December 31, 2017 as indicated in the table below:

Company	State/Municipality	State Net Income Tax Operating Loss Carryforward	Year of Expiration
		(in millions)	
AEP	Arkansas	$ 72.0	2022
AEP	Kentucky	157.6	2037
AEP	Louisiana	543.1	2037
AEP	Oklahoma	799.8	2037
AEP	Tennessee	27.9	2032
AEP	Virginia	17.8	2037
AEP	West Virginia	29.2	2037
AEP	Ohio Municipal	106.3	2022
AEPTCo	Oklahoma	296.9	2037
AEPTCo	Ohio Municipal	64.2	2022
I&M	West Virginia	14.1	2037
PSO	Oklahoma	477.0	2037
SWEPCo	Arkansas	71.2	2022
SWEPCo	Louisiana	533.4	2037

As of December 31, 2017, AEP and AEPTCo have recorded valuation allowances of $5 million and $2 million, respectively, against certain state and municipal net income tax operating loss carryforwards since future taxable income is not expected to be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires. Management anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires for each state.

As of December 31, 2017 and 2016, AEP had $0 million and $17 million, respectively, of uncertain tax positions netted against deferred tax liabilities.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2012, 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. As of December 31, 2017, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2032 through 2036.

	Total Federal	Federal Tax Credit Carryforward	Total State	State Tax Credit Carryforward

Company	Tax Credit Carryforward	Subject to Expiration	Tax Credit Carryforward	Subject to Expiration
		(in millions)		
AEP	$ 174.7	$ 145.8	$ 31.0	$ 31.0
AEP Texas	0.6	0.3	—	—
AEPTCo	0.3	0.1	—	—
APCo	16.6	6.1	—	—
I&M	10.6	10.1	—	—
OPCo	14.8	1.0	—	—
PSO	0.7	0.7	31.0	31.0
SWEPCo	0.8	0.7	—	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

In May 2013, the U.S. Supreme Court decided that the U.K. Windfall Tax imposed upon U.K. electric companies privatized between 1984 and 1996 is a creditable tax for U.S. federal income tax purposes. AEP filed protective claims asserting the creditability of the tax, dependent upon the outcome of the case. As a result of the favorable U.S. Supreme Court decision, AEP recognized a tax benefit of $80 million, plus $43 million of pretax interest income in the second quarter of 2013. In the first quarter of 2017, AEP received the tax refund related to the U.K. Windfall Tax, including interest through the date of the refund.

The Registrants recognize interest accruals related to uncertain tax positions in interest income or expense as applicable and penalties in Other Operation expense in accordance with the accounting guidance for “Income Taxes.”

The following tables show amounts reported for interest expense, interest income and reversal of prior period interest expense:

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Interest Expense	$ 1.7	$ —	$ —	$ 0.5	$ —	$ —	$ —	$ —
Interest Income	6.1	1.1	—	—	1.0	1.6	—	—
Reversal of Prior Period Interest Expense	—	—	—	—	—	—	—	—

Year Ended December 31, 2016	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Interest Expense	$ 2.7	$ —	$ —	$ —	$ 0.2	$ 0.2	$ —	$ —
Interest Income	9.9	0.2	—	0.1	—	—	0.3	—
Reversal of Prior Period Interest Expense	3.3	0.8	—	—	—	—	0.7	1.4

Year Ended December 31, 2015	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				

Interest Expense	$ 2.7	$ 0.2	$ —	$ 0.4	$ 0.2	$ 1.0	$ 0.1	$ 0.4
Interest Income	0.8	0.2	—	—	—	—	—	—
Reversal of Prior Period Interest Expense	—	—	—	—	—	—	—	—

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	Years Ended December 31,			
	2017		2016	
Company	Receipt of Interest	Payment of Interest and Penalties	Receipt of Interest	Payment of Interest and Penalties
	(in millions)			
AEP	$ 3.6	$ 8.3	$ 2.9	$ 5.8
AEP Texas	2.8	0.1	2.1	0.3
AEPTCo	—	—	—	—
APCo	—	1.0	—	0.1
I&M	—	1.3	—	0.9
OPCo	0.3	1.0	—	1.7
PSO	0.6	—	0.6	—
SWEPCo	—	—	0.1	—

The reconciliations of the beginning and ending amounts of unrecognized tax benefits are as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Balance as of January 1, 2017	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3
Increase – Tax Positions Taken During a Prior Period	4.5	2.0	—	—	0.2	—	0.1	1.7
Decrease – Tax Positions Taken During a Prior Period	(28.0)	(12.3)	—	—	(0.5)	—	(0.9)	(5.4)
Increase – Tax Positions Taken During the Current Year	3.4	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	7.9	3.0	—	—	(0.3)	—	0.7	1.6
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2017	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Balance as of January 1, 2016	$ 187.0	$ 27.8	$ —	$ 0.3	$ 2.4	$ 6.9	$ 1.3	$ 9.3
Increase – Tax Positions Taken During a Prior Period	86.0	6.5	—	—	1.8	—	0.1	1.3
Decrease – Tax Positions Taken During a Prior Period	(161.2)	(15.0)	—	(0.3)	(0.4)	—	(1.3)	(9.3)

Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(13.0)	(12.8)	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2016	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2015	$ 182.0	$ 22.6	$ —	$ —	$ 2.3	$ 6.9	$ 1.3	$ 7.5
Increase – Tax Positions Taken During a Prior Period	5.4	5.2	—	0.3	0.1	—	—	1.8
Decrease – Tax Positions Taken During a Prior Period	(0.4)	—	—	—	—	—	—	—
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2015	$ 187.0	$ 27.8	$ —	$ 0.3	$ 2.4	$ 6.9	$ 1.3	$ 9.3

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant was as follows:

Company	2017	2016	2015
		(in millions)	
AEP	$ 10.5	$ 15.8	$ 100.2
AEP Texas	(0.5)	4.2	26.0
AEPTCo	—	—	—
APCo	—	—	0.2
I&M	2.1	2.5	1.6
OPCo	4.5	4.4	4.5
PSO	—	0.1	0.9
SWEPCo	(0.5)	0.8	6.0

Federal Tax Legislation

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017, phasing down to 40% in 2018 and 30% in 2019. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 and with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit. The enacted provisions did not materially impact the

Registrants' net income or financial condition but did have a favorable impact on cash flows. The federal Tax Reform eliminated bonus depreciation for certain property acquired after September 27, 2017.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in the corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate was reduced 0.5% each year beginning after June 30, 2012, with the final reduction occurring in years beginning after June 30, 2015. Additional legislation was passed by the state of Indiana reducing the corporate income tax rate from 6.5% in 2016 to 4.9% beginning after June 30, 2016 with the final reduction occurring in years beginning after June 30, 2021. The legislation did not materially impact the Registrants' net income, cash flows or financial condition.

House Bill 32 was passed by the state of Texas in June 2015, permanently reducing the Texas income/franchise tax rate from 0.95% to 0.75% effective January 1, 2016, applicable to reports originally due on or after the effective date. The Texas income/franchise tax rate had been scheduled to return to 1% in 2016. The enacted provision did not materially impact the Registrants' net income, cash flows, or financial condition.

In March 2016, the Texas Comptroller of Public Accounts issued clarifying guidance regarding the treatment of transmission and distribution expenses included in the computation of taxable income for purposes of calculating the Texas income/franchise tax. The guidance clarified which specific transmission and distribution expenses are included in the computation of the cost of goods sold deduction. This guidance resulted in a net favorable adjustment to net income of $21 million, $7 million, $2 million and $9 million in 2016 for AEP, AEP Texas, PSO and SWEPCo, respectively.

In March 2016, Louisiana enacted several tax bills impacting income taxes, franchise taxes and sales taxes. The income tax provisions limit the use of Louisiana net operating losses and the sales tax provisions increase the sales tax rate and suspend or eliminate certain exemptions. The legislation did not materially impact the Registrants' net income, cash flows or financial condition.

Legislation was enacted in the state of Illinois in July 2017 increasing the corporate income tax rate from 5.25% to 7% effective July 1, 2017, with the increased rate applied to the portion of the tax year falling on or after that date. With the inclusion of the 2.5% Illinois Replacement tax, the total Illinois corporate income tax rate will increase from a total of 7.75% to a total of 9.5%, effective July 1, 2017. The legislation is not expected to materially impact the Registrants' net income, cash flows or financial condition.

13. LEASES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Leases of property, plant and equipment are for remaining periods up to 14 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 231.3	$ 10.5	$ 1.7	$ 17.5	$ 88.4	$ 8.2	$ 4.4	$ 5.3
Amortization of Capital Leases	66.3	4.0	—	6.9	11.1	4.1	4.0	11.2
Interest on Capital Leases	16.7	0.8	—	3.7	3.2	0.5	0.6	3.6

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Total Lease Rental Costs	$ 314.3	$ 15.3	$ 1.7	$ 28.1	$ 102.7	$ 12.8	$ 9.0	$ 20.1

Year Ended December 31, 2016	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Net Lease Expense on Operating Leases	$ 224.9	$ 9.8 (a)	$ 0.9	$ 16.6	$ 90.5	$ 7.1	$ 5.0	$ 6.7
Amortization of Capital Leases	93.7	3.4	—	6.4	35.6	4.2	3.7	13.6
Interest on Capital Leases	18.9	0.6	—	3.5	3.7	0.5	0.6	5.1
Total Lease Rental Costs	$ 337.5	$ 13.8	$ 0.9	$ 26.5	$ 129.8	$ 11.8	$ 9.3	$ 25.4

Year Ended December 31, 2015	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Net Lease Expense on Operating Leases	$ 292.6	$ 8.1 (a)	$ 0.5	$ 16.4	$ 88.3	$ 7.6	$ 5.4	$ 6.7
Amortization of Capital Leases	108.5	2.9	—	5.6	40.7	3.9	3.5	13.7
Interest on Capital Leases	25.1	0.4	—	0.8	3.3	0.6	0.7	6.2
Total Lease Rental Costs	$ 426.2 (b)	$ 11.4	$ 0.5	$ 22.8	$ 132.3	$ 12.1	$ 9.6	$ 26.6

(a) Amounts include lease expenses related to AEP Texas Wind Farms that have been classified as Other Operation Expense from Discontinued Operations on the statements of income in the amount of $1 million for each of the years ended December 31, 2016 and 2015, respectively. See Note 7 for additional information.

(b) Amounts include lease expenses related to AEPRO that have been classified as Other Operation Expense from Discontinued Operations on the statement of income in the amount of $89 million for the year ended December 31, 2015. See “AEPRO (Corporate and Other)” section of Note 7 for additional information.

The following tables show the property, plant and equipment under capital leases and related obligations recorded on the Registrants’ balance sheets. Unless shown as a separate line on the balance sheets due to materiality, current capital lease obligations are included in Other Current Liabilities and long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the Registrants’ balance sheets.

December 31, 2017	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
					(in millions)			
Property, Plant and Equipment Under Capital Leases:								
Generation	$ 141.7	$ —	$ —	$ 42.5	$ 27.2	$ —	$ 8.9	$ 33.4
Other Property, Plant and Equipment	373.3	32.7	0.2	18.0	34.0	22.8	18.0	122.4
Total Property, Plant and Equipment	515.0	32.7	0.2	60.5	61.2	22.8	26.9	155.8
Accumulated Amortization	229.0	10.0	—	19.0	21.1	10.6	15.3	94.0
Net Property, Plant and Equipment Under Capital Leases	$ 286.0	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.6	$ 61.8
Obligations Under Capital Leases:								
Noncurrent Liability	$ 238.8	$ 18.5	$ 0.1	$ 34.9	$ 34.3	$ 7.9	$ 8.3	$ 57.8
Liability Due Within One Year	59.0	4.2	0.1	6.6	5.8	4.3	3.5	11.2
Total Obligations Under Capital Leases	$ 297.8	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.8	$ 69.0

December 31, 2016	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
					(in millions)			

Property, Plant and Equipment Under Capital Leases:								
Generation	$ 146.3	$ —	$ —	$ 45.0	$ 26.4	$ —	$ 10.0	$ 34.5
Other Property, Plant and Equipment	373.1	26.1	—	18.1	43.7	23.9	19.4	122.1
Total Property, Plant and Equipment	519.4	26.1	—	63.1	70.1	23.9	29.4	156.6
Accumulated Amortization	226.4	7.7	—	18.1	25.4	11.6	15.6	86.5
Net Property, Plant and Equipment Under Capital Leases	$ 293.0	$ 18.4	$ —	$ 45.0	$ 44.7	$ 12.3	$ 13.8	$ 70.1
Obligations Under Capital Leases:								
Noncurrent Liability	$ 242.1	$ 14.8	$ —	$ 38.2	$ 35.3	$ 8.1	$ 9.8	$ 65.5
Liability Due Within One Year	63.4	3.6	—	6.8	9.4	4.2	4.1	11.8
Total Obligations Under Capital Leases	$ 305.5	$ 18.4	$ —	$ 45.0	$ 44.7	$ 12.3	$ 13.9	$ 77.3

Future minimum lease payments consisted of the following as of December 31, 2017:

Capital Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2018	$ 76.6	$ 5.1	$ 0.1	$ 10.0	$ 11.0	$ 4.7	$ 3.8	$ 14.3
2019	60.4	4.0	0.1	7.9	7.2	2.4	2.5	12.7
2020	49.7	3.4	—	7.0	6.4	1.8	1.7	10.9
2021	42.6	3.1	—	6.8	5.9	1.6	1.3	10.0
2022	35.1	2.6	—	6.4	5.4	1.1	1.0	8.9
Later Years	106.2	8.3	—	18.8	25.2	2.0	2.6	25.6
Total Future Minimum Lease Payments	370.6	26.5	0.2	56.9	61.1	13.6	12.9	82.4
Less Estimated Interest Element	72.8	3.8	—	15.4	21.0	1.4	1.3	13.4
Estimated Present Value of Future Minimum Lease Payments	$ 297.8	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.6	$ 69.0

Noncancelable Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2018	$ 245.9	$ 11.6	$ 1.7	$ 17.3	$ 91.3	$ 11.3	$ 4.8	$ 6.0
2019	237.9	10.7	1.3	15.6	90.3	10.3	4.3	5.7
2020	227.6	9.8	1.0	14.4	86.9	8.7	3.8	5.3
2021	210.7	8.9	0.4	12.0	82.4	6.3	2.9	4.9
2022	201.1	7.9	—	10.9	81.4	5.4	2.5	4.3
Later Years	137.1	21.5	—	23.3	16.3	19.5	6.5	9.5
Total Future Minimum Lease Payments	$ 1,260.3	$ 70.4	$ 4.4	$ 93.5	$ 448.6	$ 61.5	$ 24.8	$ 35.7

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of December 31, 2017, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company		Maximum Potential Loss
		(in millions)
AEP	$	43.2
AEP Texas		10.0
APCo		8.8
I&M		3.3
OPCo		6.4
PSO		3.6
SWEPCo		3.7

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2017 are as follows:

Future Minimum Lease Payments		AEP (a)		I&M
		(in millions)		
2018	$	147.8	$	73.9
2019		147.8		73.9
2020		147.8		73.9
2021		147.8		73.9
2022		147.2		73.6
Total Future Minimum Lease Payments	$	738.4	$	369.2

(a) AEP’s future minimum lease payments include equal shares from AEGCo and I&M.

Railcar Lease (Applies to AEP, I&M and SWEPCo)

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $7 million and $8 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2017. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are $8 million and $10 million for I&M and SWEPCo, respectively, as of December 31, 2017, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. See "AEPRO (Corporate and Other)" section of Note 7. Certain of the boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2027. As of December 31, 2017, the maximum potential amount of future payments required under the guaranteed leases was $50 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of December 31, 2017, AEP's boat and barge lease guarantee liability was $7 million, of which $1 million was recorded in Other Current Liabilities and $6 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

I&M Nuclear Fuel Lease (Applies to AEP and I&M)

In November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future minimum lease payments for the sales-and-leaseback transaction as of December 31, 2017 are $2 million based on estimated fuel burn and will be paid in 2018. The net capital lease asset is included in Other Property, Plant and Equipment on the balance sheets. The short-term capital lease obligations are included in Other Current Liabilities on AEP's balance sheets and in Obligations Under Capital Leases on I&M's balance sheets. The long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

14. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Common Stock (Applies to AEP)

Listed below is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2014	509,739,159	20,336,592

Issued	1,650,014	—	
Balance, December 31, 2015	511,389,173	20,336,592	
Issued	659,347	—	
Balance, December 31, 2016	512,048,520	20,336,592	
Issued	162,124	—	
Treasury Stock Reissued	—	(131,546)	(a)
Balance, December 31, 2017	512,210,644	20,205,046	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Share-based Compensation. See "Shared-based Compensation Plans" section of Note 15 for additional information.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted Average Interest Rate as of December 31, 2017	Interest Rate Ranges as of December 31, 2017	2016	Outstanding as of December 31, 2017	2016	
AEP					(in millions)		
Senior Unsecured Notes	2017-2047	4.62%	2.15%-8.13%	1.65%-8.13%	$ 16,478.3	$ 14,761.0	(f)
Pollution Control Bonds (a)	2017-2042 (b)	3.06%	1.54%-6.30%	0.69%-6.30%	1,621.7	1,725.1	
Notes Payable – Nonaffiliated (c)	2017-2032	3.00%	2.03%-6.37%	1.456%-6.37%	260.8	326.9	
Securitization Bonds	2017-2028 (d)	3.70%	1.98%-5.31%	0.88%-5.31%	1,416.5	1,705.0	
Spent Nuclear Fuel Obligation (e)					268.6	266.3	
Other Long-term Debt	2017-2059	2.75%	1.15%-13.718%	1.15%-13.718%	1,127.4	1,606.9	
Total Long-term Debt Outstanding					$ 21,173.3	$ 20,391.2	(f)
AEP Texas							
Senior Unsecured Notes	2018-2047	4.12%	2.40%-6.76%	2.61%-6.76%	$ 1,932.2	$ 1,241.3	
Pollution Control Bonds (a)	2017-2030	4.39%	1.75%-6.30%	4.00%-6.30%	490.5	530.3	
Securitization Bonds	2017-2024 (d)	4.05%	1.98%-5.31%	0.88%-5.31%	1,026.1	1,245.8	
Other Long-term Debt	2019-2059	2.76%	2.75%-4.50%	2.438%-4.50%	200.5	200.3	
Total Long-term Debt Outstanding					$ 3,649.3	$ 3,217.7	
AEPTCo							
Senior Unsecured Notes	2018-2047	3.85%	2.68%-5.52%	2.68%-5.52%	$ 2,550.4	$ 1,932.0	
Total Long-term Debt Outstanding					$ 2,550.4	$ 1,932.0	
APCo							
Senior Unsecured Notes	2017-2045	5.20%	3.30%-7.00%	3.40%-7.00%	$ 3,045.1	$ 2,972.4	
Pollution Control Bonds (a)	2018-2042 (b)	2.44%	1.625%-5.38%	0.69%-5.38%	512.2	615.8	
Securitization Bonds	2023-2028 (d)	2.98%	2.008%-3.772%	2.008%-3.772%	295.9	318.9	
Other Long-term Debt	2019-2026	2.92%	2.73%-13.718%	2.06%-13.718%	126.9	126.8	
Total Long-term Debt Outstanding					$ 3,980.1	$ 4,033.9	
I&M							
Senior Unsecured Notes	2019-2047	5.20%	3.20%-7.00%	3.20%-7.00%	$ 1,809.0	$ 1,512.8	
Pollution Control Bonds (a)	2018-2025 (b)	2.02%	1.75%-2.75%	0.74%-4.625%	264.6	225.4	
Notes Payable – Nonaffiliated (c)	2017-2022	2.15%	2.03%-2.19%	1.456%-1.81%	188.6	251.4	

Spent Nuclear Fuel Obligation (e)					268.6	266.3
Other Long-term Debt	2018-2025	3.03%	2.82%-6.00%	2.15%-6.00%	214.3	215.5
Total Long-term Debt Outstanding					$ 2,745.1	$ 2,471.4
OPCo						
Senior Unsecured Notes	2018-2035	5.98%	5.375%-6.60%	5.375%-6.60%	$ 1,591.4	$ 1,590.2
Pollution Control Bonds	2038	5.80%	5.80%	5.80%	32.3	32.3
Securitization Bonds	2018-2019 (d)	2.049%	2.049%	0.958%-2.049%	94.5	140.2
Other Long-term Debt	2028	1.15%	1.15%	1.15%	1.1	1.2
Total Long-term Debt Outstanding					$ 1,719.3	$ 1,763.9
PSO						
Senior Unsecured Notes	2019-2046	4.80%	3.05%-6.625%	3.05%-6.625%	$ 1,144.1	$ 1,143.2
Pollution Control Bonds (a)	2020	4.45%	4.45%	4.45%	12.6	12.6
Other Long-term Debt	2019-2027	2.60%	2.584%-3.00%	1.92%-3.00%	129.8	130.2
Total Long-term Debt Outstanding					$ 1,286.5	$ 1,286.0
SWEPCo						
Senior Unsecured Notes	2017-2045	4.78%	2.75%-6.45%	2.75%-6.45%	$ 2,110.7	$ 2,359.2
Pollution Control Bonds (a)	2018-2019	3.62%	1.60%-4.95%	1.60%-4.95%	135.1	134.9
Notes Payable – Nonaffiliated (c)	2024-2032	5.20%	4.58%-6.37%	4.58%-6.37%	72.1	75.3
Other Long-term Debt	2017-2023	3.00%	2.925%-4.28%	2.346%-4.28%	124.0	109.7
Total Long-term Debt Outstanding					$ 2,441.9	$ 2,679.1

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.
(b) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.
(e) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).
(f) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet. See "Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)" section of Note 7 for additional information.

Long-term debt outstanding as of December 31, 2017 is payable as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
2018	$ 1,753.7	$ 266.1	$ 50.0	$ 249.2	$ 474.7	$ 397.0	$ 0.5	$ 3.7
2019	2,307.9	501.1	85.0	305.4	535.2	48.0	375.5	457.2
2020	1,322.0	377.7	—	90.3	26.4	0.1	13.2	118.7
2021	1,352.9	66.2	50.0	393.0	49.9	500.1	250.5	3.7
2022	1,318.4	493.1	104.0	26.0	3.5	0.1	0.5	278.7
After 2022	13,265.7	1,970.5	2,286.0	2,951.0	1,673.9	782.9	652.5	1,594.9
Principal Amount	21,320.6	3,674.7	2,575.0	4,014.9	2,763.6	1,728.2	1,292.7	2,456.9
Unamortized Discount, Net and Debt Issuance Costs	(147.3)	(25.4)	(24.6)	(34.8)	(18.5)	(8.9)	(6.2)	(15.0)
Total Long-term Debt Outstanding	$ 21,173.3	$ 3,649.3	$ 2,550.4	$ 3,980.1	$ 2,745.1	$ 1,719.3	$ 1,286.5	$ 2,441.9

In January and February 2018, I&M retired $14 million and $2 million, respectively, of Notes Payable related to DCC Fuel.

In January 2018, AEP Texas retired $96 million of Securitization Bonds.

In January 2018, OPCo retired $23 million of Securitization Bonds.

In January 2018, SWEPCo issued $450 million of 3.85% Senior Unsecured Notes due in 2048.

In January 2018, Transource Energy issued $2 million of variable rate Other Long-term Debt due in 2020.

In February 2018, APCo retired $12 million of Securitization Bonds.

In February 2018, SWEPCo retired $2 million of Other Long-term Debt.

As of December 31, 2017, trustees held, on behalf of AEP, $678 million of their reacquired Pollution Control Bonds. Of this total, $104 million and $345 million related to APCo and OPCo, respectively.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 0.6% of consolidated tangible net assets as of December 31,2017. The method for calculating the consolidated tangible net assets is contractually defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries also have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

The most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2017, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $11.4 billion.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. However, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2017, the amount of any such restrictions was as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Restricted Retained Earnings	$ 1,375.6 (a)	$ 219.6	$ —	$ —	$ 416.2	$ —	$ 173.5	$ 470.6

(a) Includes the restrictions of consolidated and unconsolidated subsidiaries.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must 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 the credit agreements. As of December 31, 2017, AEP had $7.3 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.2 billion, $1.1 billion and $1.1 billion of dividends to common shareholders for the years ended December 31, 2017, 2016 and 2015, respectively.

Lines of Credit and Short-term Debt (Applies to AEP and SWEPCo)

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 of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2017, AEP had a credit facility for $3 billion to support its commercial paper program. The maximum amount of commercial paper outstanding during 2017 was $1.6 billion and the weighted average interest rate of commercial paper outstanding during 2017 was 1.25%. AEP's outstanding short-term debt was as follows:

		December 31,			
		2017		2016	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in millions)		(in millions)	
AEP	Securitized Debt for Receivables (b)	$ 718.0	1.22%	$ 673.0	0.70%
AEP	Commercial Paper	898.6	1.85%	1,040.0	1.02%
SWEPCo	Notes Payable	22.0	2.92%	—	—%
	Total Short-term Debt	$ 1,638.6		$ 1,713.0	

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

Corporate Borrowing Program – AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries, a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries, and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2017 and 2016 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2017:

Maximum	Average	Net Loans to

Company	Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	(Borrowings from) the Utility Money Pool as of December 31, 2017	Authorized Short-term Borrowing Limit	
	(in millions)						
AEP Texas	$ 296.0	$ 451.7	$ 194.8	$ 264.6	$ 103.5	$ 400.0	
AEPTCo	467.2	268.0	180.5	119.8	109.2	795.0	(a)
APCo	231.5	160.7	144.3	30.0	(162.5)	600.0	
I&M	367.4	12.6	204.9	12.6	(199.2)	500.0	
OPCo	280.6	56.2	137.0	27.9	(87.8)	400.0	
PSO	185.2	—	119.3	—	(149.6)	300.0	
SWEPCo	187.5	178.6	95.5	169.5	(118.7)	350.0	

Year Ended December 31, 2016:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2016	Authorized Short-term Borrowing Limit	
	(in millions)						
AEP Texas	$ 176.9	$ 138.9	$ 87.5	$ 79.8	$ (174.5)	$ 400.0	
AEPTCo	363.4	82.0	153.7 —	14.6	49.8	795.0	(a)
APCo	286.9	25.7	148.0	24.8	(55.5)	600.0	
I&M	369.1	97.6	129.9	19.5	(202.7)	500.0	
OPCo	227.9	379.2	116.6	182.4	24.2	400.0	
PSO	52.0	205.4	12.9	48.1	(52.0)	300.0	
SWEPCo	249.4	313.3	171.8	267.7	167.8	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above tables does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary AEP Texas North Generation Company LLC (TNGC) and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LP are participants in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2017 and 2016 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2017:

Company	Maximum Borrowings from the Nonutility Money Pool	Maximum Loans to the Nonutility Money Pool	Average Borrowings from the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Net Loans to the Nonutility Money Pool as of December 31, 2017
	(in millions)				
AEP Texas	$ —	$ 8.6	$ —	$ 8.3	$ 8.4
SWEPCo	—	2.0	—	2.0	2.0

Year Ended December 31, 2016:

Company	Maximum Borrowings from the Nonutility Money Pool	Maximum Loans to the Nonutility Money Pool	Average Borrowings from the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Net Loans to the Nonutility Money Pool as of December 31, 2016
	(in millions)				
AEP Texas (a)	$ 12.5	$ 27.0	$ 12.0	$ 12.3	$ 8.6
SWEPCo	—	2.0	—	2.0	2.0

(a) Amounts include short-term loans and (borrowings) related to Wind Farms that have been classified as Assets and Liabilities From Discontinued Operations, which were transferred to a competitive AEP Affiliate in December 2016. See Note 7 for additional information.

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. In January 2017, management removed AEP Texas from the direct financing relationship with AEP to better reflect current business operations. The amounts of outstanding loans to (borrowings from) AEP as of December 31, 2017 and 2016 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each Registrant Subsidiaries' balance sheets. The direct borrowing and lending activity with AEP are described in the following tables:

Year Ended December 31, 2017:

Company	Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2017	Loans to AEP as of December 31, 2017	Authorized Short-term Borrowing Limit	
	(in millions)							
AEP Texas	$ —	$ —	$ —	$ —	$ —	$ —	$ —	
AEPTCo	4.1	151.9	1.1	39.3	1.1	22.5	75.0	(b)

Year Ended December 31, 2016:

Company	Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2016	Loans to AEP as of December 31, 2016	Authorized Short-term Borrowing Limit	
	(in millions)							
AEP Texas (a)	$ 55.0	$ 5.0	$ 42.5	$ 5.0	$ —	$ 5.0	$ —	
AEPTCo	5.6	170.4	1.0	35.7	1.0	14.2	75.0	(b)

(a) Amounts include short-term loans and (borrowings) related to Wind Farms that have been classified as Assets and Liabilities From Discontinued Operations, which were transferred to a competitive AEP Affiliate in December 2016. See Note 7 for additional information.
(b) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Years Ended December 31,		
	2017	2016	2015
Maximum Interest Rate	1.85%	1.02%	0.87%
Minimum Interest Rate	0.92%	0.69%	0.37%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for Years Ended December 31,		
Company	2017	2016	2015	2017	2016	2015
AEP Texas	1.29%	0.88%	0.46%	1.26%	0.72%	0.52%
AEPTCo	1.36%	0.85%	0.46%	1.27%	0.83%	0.49%
APCo	1.28%	0.80%	0.53%	1.29%	0.82%	0.47%
I&M	1.27%	0.80%	0.49%	1.29%	0.80%	0.48%
OPCo	1.37%	0.85%	—%	0.98%	0.74%	0.48%
PSO	1.32%	0.96%	0.49%	—%	0.83%	0.48%
SWEPCo	1.28%	0.79%	0.53%	0.98%	0.90%	0.48%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool are summarized in the following tables:

Year Ended December 31, 2017:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	—%	—%	1.85%	—%	—%	1.32%
SWEPCo	—%	—%	1.85%	—%	—%	1.32%

Year Ended December 31, 2016:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	1.11%	0.97%	1.02%	0.75%	1.00%	0.86%
SWEPCo	—%	—%	1.02%	0.69%	—%	0.82%

Year Ended December 31, 2015:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool

AEP Texas	1.14%	0.64%	—%	—%	0.76%	—%
SWEPCo	—%	—%	0.87%	0.37%	—%	0.48%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following tables:

Year Ended December 31, 2017:

Company	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
AEP Texas	—%	—%	—%	—%	—%	—%
AEPTCo	1.85%	0.92%	1.85%	0.92%	1.33%	1.36%

Year Ended December 31, 2016:

Company	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
AEP Texas	0.98%	0.69%	1.02%	0.99%	0.83%	1.00%
AEPTCo	1.02%	0.69%	1.02%	0.69%	0.83%	0.87%

Year Ended December 31, 2015:

Company	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
AEP Texas	0.87%	0.37%	—%	—%	0.48%	—%
AEPTCo	0.87%	0.37%	0.87%	0.37%	0.48%	0.47%

Interest expense and interest income related to the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense and Interest Income, respectively, on each of the Registrant Subsidiaries' statements of income. The interest expense and interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2017, 2016 and 2015.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 6.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

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

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2019.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2017	2016	2015
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	1.22%	0.70%	0.30%
Net Uncollectible Accounts Receivable Written Off	$ 23.4	$ 23.7	$ 34.1

	December 31, 2017	2016
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 925.5	$ 945.0
Short-term – Securitized Debt of Receivables	718.0	673.0
Delinquent Securitized Accounts Receivable	41.1	42.7
Bad Debt Reserves Related to Securitization	28.7	27.7
Unbilled Receivables Related to Securitization	303.2	322.1

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEPTCo and AEP Texas)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary were as follows:

Company	December 31, 2017	2016
	(in millions)	
APCo	$ 136.2	$ 142.0
I&M	136.5	136.7
OPCo	367.4	388.3
PSO	115.1	110.4
SWEPCo	138.2	130.9

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2017	2016	2015

		(in millions)	
APCo	$ 5.6	$ 6.7	$ 7.6
I&M	6.7	7.1	8.4
OPCo	21.7	28.9	30.7
PSO	7.0	6.2	5.8
SWEPCo	7.2	6.9	7.0

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

	Years Ended December 31,		
Company	2017	2016	2015
		(in millions)	
APCo	$ 1,372.8	$ 1,412.5	$ 1,453.8
I&M	1,612.9	1,596.2	1,553.0
OPCo	2,339.0	2,633.0	2,569.4
PSO	1,337.0	1,269.3	1,326.1
SWEPCo	1,563.4	1,531.7	1,597.8

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

Awards under AEP's long-term incentive plan may be granted to employees and directors. The Amended and Restated American Electric Power System Long-Term Incentive Plan (the "Prior Plan"), was replaced prospectively for new grants by the American Electric Power System 2015 Long-Term Incentive Plan (the "2015 LTIP") effective in April 2015. The 2015 LTIP was subsequently amended in September 2016. The 2015 LTIP provides for a maximum of 10 million common shares to be available for grant to eligible employees and directors. As of December 31, 2017, 9,011,946 shares remained available for issuance under the 2015 LTIP plan. No new awards may be granted under the Prior Plan. The 2015 LTIP awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance share units, cash-based awards and other stock-based awards. If a share is issued pursuant to a stock option or a stock appreciation right, it will reduce the aggregate amount authorized under the 2015 LTIP by 0.286 of a share. If a share is issued for any other award that settles in AEP stock, it will reduce the aggregate amount authorized under the 2015 LTIP by one share. Cash settled awards do not reduce the aggregate amount authorized under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Units

Performance units granted prior to 2017 are settled in cash rather than AEP common stock and do not reduce the aggregate share authorization. These performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. Performance units granted in 2017 will be settled in AEP common stock and will reduce the aggregate share authorization. In all cases the number of performance units held at the end of the three year performance period is multiplied by the performance score for such period to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy stock ownership requirements. If those employees have not met their stock ownership requirements, a portion or all of their performance units are mandatorily deferred as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid in Capital on the balance sheet. Amounts equivalent to cash dividends on both performance units and AEP career shares accrue as additional units. Management records compensation cost for performance units over an approximately three-year vesting period. The liability for the pre 2017 performance units is recorded in Employee Benefits and Pension Obligations on the balance sheet and is adjusted for changes in value. Performance units settled in shares are recorded as mezzanine equity on the balance sheet and compensation cost is calculated at fair value using two metrics. Half is based on the total shareholder return measure, which is determined based on a third party Monte Carlo valuation. That metric doesn't change over the three year vesting period. The other half is based on a three year cumulative earnings per share metric which is adjusted quarterly for changes in performance relative to a target approved by the HR Committee.

Monte Carlo Valuation

AEP engaged a third party for a Monte Carlo valuation to calculate half of the fair value for the performance units awarded during 2017. The valuation used a lattice model and the expected volatility assumption used was the historical volatilities for AEP and the members of their peer group over the last 2.86 years (period from award date to vesting date). The range of expected volatilities was 15.65% to 27.19% with an average expected volatility of 19.07%. The dividend rates used were 0% which is the equivalent to reinvesting dividends. The risk-free rate used was 1.44%, which was interpolated between the two year rate of 1.21% and three year rate of 1.48% since 2.86 years was the vesting period from award date to vesting date.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP career shares for the years ended December 31, 2017, 2016 and 2015 as follows:

	Years Ended December 31,		
Performance Units	**2017**	**2016**	**2015**
Awarded Units (in thousands) (a)	590.7	597.4	575.0
Weighted Average Unit Fair Value at Grant Date	$ 69.78	$ 62.77	$ 59.19
Vesting Period (in years)	3	3	3

	Years Ended December 31,		
Performance Units and AEP Career Shares (Reinvested Dividends Portion)	**2017**	**2016**	**2015**
Awarded Units (in thousands) (c)	74.6	89.2	103.6
Weighted Average Fair Value at Grant Date	$ 72.35	$ 63.83	$ 54.35
Vesting Period (in years)	(b)	(b)	(b)

(a) Awarded units in 2017 are mezzanine equity awards and awarded units in 2016 and 2015 are liability awards.
(b) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.
(c) In 2017 the awarded dividends were a mix of equity awards and liability awards, while they were all liability awards in 2016 and 2015.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The performance scores for all performance periods were dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to a peer group of similar companies (b) three-year cumulative earnings per share measured relative to a target approved by the HR Committee.

The certified performance scores and units earned for the three-year periods ended December 31, 2017, 2016 and 2015 were as follows:

Performance Units	Years Ended December 31, 2017	2016	2015
Certified Performance Score	164.8%	163.9%	176.3%
Performance Units Earned	956,055	1,111,966	1,202,107
Performance Units Mandatorily Deferred as AEP Career Shares	20,213	9,963	41,707
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	47,177	51,684	54,074
Performance Units to be Settled in Cash	888,665	1,050,319	1,106,326

The settlements for the years ended December 31, 2017, 2016 and 2015 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2017	2016	2015
		(in millions)	
Cash Settlements for Performance Units	$ 64.9	$ 62.7	$ 48.1
Cash Settlements for Career Share Distributions	—	9.1	3.0
AEP Common Stock Settlements for Career Share Distributions	0.4	—	—

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting, except that RSUs granted prior to 2017 that vest to AEP's executive officers are settled in cash. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. For RSUs settled in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs settled in cash, compensation cost is recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting is determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 72 months from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four Chief Executive Officer succession candidates as a retention incentive for these candidates. These grants vested in three approximately equal installments in August 2013, August 2014 and August 2015.

The HR Committee awarded RSUs, including additional units awarded as dividends, for the years ended December 31, 2017, 2016 and 2015 as follows:

Restricted Stock Units	Years Ended December 31, 2017	2016	2015
Awarded Units (in thousands)	255.8	242.0	397.5
Weighted Average Grant Date Fair Value	$ 65.26	$ 62.88	$ 58.56

The total fair value and total intrinsic value of restricted stock units vested during the years ended December 31, 2017, 2016 and 2015 were as follows:

Restricted Stock Units	Years Ended December 31, 2017	2016	2015
	(in millions)		
Fair Value of Restricted Stock Units Vested	$ 16.1	$ 16.4	$ 18.3
Intrinsic Value of Restricted Stock Units Vested (a)	20.0	21.0	24.2

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2017 and changes during the year ended December 31, 2017 are as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2017	603.6	$ 57.54
Granted	255.8	65.26
Vested	(295.1)	54.72
Forfeited	(34.7)	61.53
Nonvested as of December 31, 2017	529.6	62.13

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2017 was $39 million and the weighted average remaining contractual life was 1.6 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to Non-Employee Directors are fully vested upon grant date. Stock units are settled in cash upon termination of board service or up to 10 years later if the participant so elects. Cash settlements for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. After five years of service on the Board of Directors, non-employee directors receive contributions to an AEP stock fund awarded under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investments that are similar to the investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan.

Management records compensation cost for stock units when the units are awarded and adjusts the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

For 2017, 2016 and 2015, cash settlements for stock unit distributions were immaterial.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2017, 2016 and 2015 as follows:

Years Ended December 31,

Stock Unit Accumulation Plan for Non-Employee Directors	2017	2016	2015
Awarded Units (in thousands)	14.8	19.1	24.9
Weighted Average Grant Date Fair Value	$ 70.79	$ 64.96	$ 55.46

Share-based Compensation Plans

Compensation cost for share-based payment arrangements, the actual tax benefit from the tax deductions for compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2017, 2016 and 2015 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2017**	**2016**	**2015**
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 79.5	$ 66.5	$ 63.8
Actual Tax Benefit (b)	18.9	23.3	22.3
Total Compensation Cost Capitalized	26.4	20.8	20.3

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

(b) In December 2017, Tax Reform modified Section 162(m) of the Internal Revenue Code. Beginning after 2017, AEP can no longer deduct compensation expense in excess of $1 million for certain named executive officers. This will reduce the tax benefit going forward.

As of December 31, 2017, there was $64 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP and Prior Plan. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance units are adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.35 years.

Under the 2015 LTIP and Prior Plan, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. In 2017, AEP used a combination of all three to fulfill share commitments. AEP's current practice is to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset AEP's tax withholding obligation.

16. RELATED PARTY TRANSACTIONS

The disclosures in this note apply to all Registrant Subsidiaries unless indicated otherwise.

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 12 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (PCA), Bridge Agreement and Power Supply Agreement (PSA) (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the following agreements.

- A Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies would fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR committed to use its capacity to help meet the PJM capacity obligations of member companies through the PJM planning year that ended May 31, 2015.
- A Power Supply Agreement (PSA) between AGR and OPCo that provided for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that was not acquired through auctions in 2014.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Effective January 1, 2014 and revised in May 2015, power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. Effective January 1, 2014 and with the transfer of OPCo's generation assets to AGR, AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

System Integration Agreement (SIA) (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM and MISO generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The following tables show the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2017, 2016 and 2015:

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2017							
Direct Sales to East Affiliates	$ —	$ —	$ 130.4	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	3.8	—	—	—
Auction Sales to OPCo (a)	—	—	1.0	—	—	—	—
Direct Sales to AEPEP	63.6	—	—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	572.0	34.1	(4.4)	6.2	—	24.2
Other Revenues	2.1	8.5	6.5	2.4	18.2	4.3	1.9
Total Affiliated Revenues	$ 65.7	$ 580.5	$ 172.0	$ 1.8	$ 24.4	$ 4.3	$ 25.9

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2016							
Direct Sales to East Affiliates	$ —	$ —	$ 126.0	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	3.7
Auction Sales to OPCo (a)	—	—	9.2	12.0	—	—	—
Direct Sales to AEPEP	73.9	—	—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	366.1	1.3	12.2	(2.0)	(1.7)	19.4
Other Revenues	1.8	—	5.6	2.0	19.3	4.3	1.6
Total Affiliated Revenues	$ 75.7	$ 366.1	$ 142.1	$ 26.2	$ 17.3	$ 2.6	$ 24.5

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2015							
Direct Sales to East Affiliates	$ —	$ —	$ 132.1	$ —	$ —	$ —	$ —
Auction Sales to OPCo (a)	—	—	10.6	17.1	—	—	—
Direct Sales to AEPEP	76.9	—	—	—	29.7	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	225.6	0.7	8.4	35.5	0.2	15.2
Other Revenues	1.6	—	4.4	1.9	18.9	4.4	1.6
Total Affiliated Revenues	$ 78.5	$ 225.6	$ 147.8	$ 27.4	$ 84.1	$ 4.6	$ 16.6

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.

The following tables show the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2017, 2016 and 2015. AEP Texas, AEPTCo, APCo and SWEPCo did not purchase any power from affiliates for the years ended December 31, 2017, 2016 and 2015.

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2017			
Auction Purchases from AEPEP (a)	$ —	$ 96.5	$ —
Auction Purchases from AEP Energy (a)	—	5.5	—
Auction Purchases from AEPSC (a)	—	6.5	—
Direct Purchases from AEGCo	223.9	—	—
Total Affiliated Purchases	$ 223.9	$ 108.5	$ —

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2016			
Direct Purchases from West Affiliates	$ —	$ —	$ 3.7
Auction Purchases from AEPEP (a)	—	110.1	—
Auction Purchases from AEP Energy (a)	—	7.7	—
Auction Purchases from AEPSC (a)	—	24.1	—

	I&M	OPCo	PSO
Direct Purchases from AEGCo	228.6	—	—
Total Affiliated Purchases	$ 228.6	$ 141.9	$ 3.7

Related Party Purchases	**I&M**	**OPCo**	**PSO**
		(in millions)	
Year Ended December 31, 2015			
Direct Purchases from AGR (b)	$ —	$ 269.2	$ —
Auction Purchases from AEPEP (a)	—	225.2	—
Auction Purchases from AEPSC (a)	—	32.7	—
Direct Purchases from AEGCo	232.1	—	—
Total Affiliated Purchases	$ 232.1	$ 527.1	$ —

(a) Refer to the Ohio Auctions section below for further information regarding this amount.
(b) Amount excludes $31 million in 2015 which is now presented as Generation Deferrals on the Statement of Income.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

Transmission Agreement (TA) and Transmission Coordination Agreement (TCA) (Applies to all Registrant Subsidiaries except AEP Texas)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis.

The following table shows the net charges recorded by APCo, I&M and OPCo for the years ended December 31, 2017, 2016 and 2015 related to the TA:

Company	**Years Ended December 31, 2017**	**2016**	**2015**
		(in millions)	
APCo	$ 158.2	$ 103.2	$ 92.7
I&M	103.8	53.0	38.0
OPCo	248.6	143.6	81.0

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP.

The following table shows the net (revenues) expenses allocated among parties to the TCA pursuant to the SPP OATT protocols as described above for the years ended December 31, 2017, 2016 and 2015:

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
PSO	$ 56.0	$ 19.6	$ 15.0
SWEPCo	6.6	(19.6)	(15.0)

The net revenues shown above are recorded in Sales to AEP Affiliates on the statements of income and the net expenses are recorded in Other Operation expenses on the statements of income.

AEPTCo is a load serving entity within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. AEPTCo recorded affiliated transmission revenues related to the TA and TCA in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

ERCOT Transmission Service Charges (Applies to AEP Texas)

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $30 million, $29 million and $27 million for transmission services in 2017, 2016 and 2015, respectively. The billings are recorded in Other Operation expenses on AEP Texas' statements of income.

Oklaunion PPA between AEP Texas and AEPEP (Applies to AEP Texas)

On January 1, 2007, AEP Texas began a PPA with an affiliate, AEPEP, whereby AEP Texas agrees to sell AEPEP 100% of AEP Texas' capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Plant. This PPA is effective through December 2027. AEPEP is to pay AEP Texas for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. In the event AEP Texas or AEPEP terminate the PPA or the Oklaunion Plant is closed by a vote of its owners prior to December

2027, AEPEP will make a payment to AEP Texas equal to AEP Texas's net book value of Oklaunion Plant at the time of such termination or plant closure. There are no penalties if AEP Texas fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC. AEP Texas recognizes revenues for the fuel, operations and maintenance and all other taxes as-billed. Revenue is recognized for the capacity and depreciation billed to AEPEP, on a straight-line basis over the term of the PPA as these represent the minimum payments due.

AEP Texas recorded revenue of $64 million, $74 million and $77 million from AEPEP for the years ended December 31, 2017, 2016 and 2015, respectively. These amounts are included in Sales to AEP Affiliates on AEP Texas' statements of income.

Joint License Agreement (Applies to AEPTCo, I&M, KPCo, OPCo and PSO)

AEPTCo entered into 50-year joint license agreement with I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. After the expiration of the agreement, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. For the years ended December 31, 2017, 2016 and 2015, AEPTCo recorded the following costs in Other Operation expense related to these agreements:

Years Ended December 31,

Billing Company	2017	2016	2015
	(in millions)		
I&M	$ 1.4	$ 0.8	$ 0.6
KPCo	0.2	0.1	—
OPCo	2.4	2.3	2.0
PSO	0.3	0.2	0.3

I&M, KPCo, OPCo and PSO recorded income related to these agreements in Sales to AEP Affiliates on the statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements (UPA) (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading costs in 2017, 2016 and 2015 were as follows:

	Years Ended December 31,		
Company	2017	2016	2015
	(in millions)		
I&M	$ 10.2	$ 12.8	$ 15.8

I&M recorded the cost of transloading services in Fuel on the balance sheet.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance costs in 2017, 2016 and 2015 were as follows:

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
I&M	$ 1.3	$ 1.7	$ 2.0
PSO	0.5	0.6	0.2
SWEPCo	3.5	3.3	2.8

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
AEGCo	$ 15.3	$ 14.8	$ 16.1
AGR	0.1	0.3	4.9
APCo	37.2	36.9	37.7
KPCo	5.0	5.3	4.6
WPCo	5.0	4.8	—
AEP River Operations LLC – (Nonutility Subsidiary of AEP)	—	—	15.5

Services Provided by AEP River Operations LLC (Applies to I&M)

AEP River Operations LLC provided services for barge towing, chartering and general and administrative expenses to I&M. The costs are recorded by I&M as Other Operation expenses on the statement of income. In October 2015, AEP signed a Purchase and Sale Agreement to sell AEP River Operations LLC to a nonaffiliated party. The sale closed in November 2015. For the year ended December 31, 2015, I&M recorded expenses of $19 million for these activities.

Central Machine Shop (Applies to APCo, I&M, PSO and SWEPCo)

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
AEGCo	$ —	$ —	$ 0.1

AGR	1.2	2.0	2.7
I&M	2.7	2.9	2.5
KPCo	1.8	1.5	1.3
PSO	1.1	0.5	0.2
SWEPCo	0.8	0.9	0.8

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value, for the years ended December 31, 2017, 2016 and 2015:

Sales

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
AEP Texas	$ 0.2	$ 0.3	$ 0.6
AEPTCo	—	—	0.2
APCo	3.5	4.5	9.4
I&M	5.0	5.2	3.0
OPCo	2.9	1.9	2.4
PSO	1.5	7.5	7.1
SWEPCo	0.5	1.0	0.8

Purchases

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
AEP Texas	$ 0.4	$ 0.7	$ 0.9
AEPTCo	9.1	6.5	0.4
APCo	0.9	1.5	8.6
I&M	3.5	2.7	8.1
OPCo	1.6	1.7	2.1
PSO	0.2	3.2	0.6
SWEPCo	0.4	6.5	7.4

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

17. VARIABLE INTEREST ENTITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

AEP is the primary beneficiary of Sabine, DCC Fuel, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, AEP Credit, a protected cell of EIS and Transource Energy. In addition, AEP has not provided material financial or other support to any of these entities that was not previously contractually required. AEP holds a significant variable interest in DHLC, OVEC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Consolidated Variable Interests Entities (Applies to all Registrants except AEPTCo and PSO)

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2017, 2016 and 2015 were $137 million, $162 million and $152 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2017, 2016 and 2015 were $136 million, $101 million and $115 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. The securitized bonds totaled $1 billion and $1.2 billion as of December 31, 2017 and 2016, respectively, and are included in Long-term Debt Due Within

One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Transition

Funding has securitized transition assets of $870 million and $1.1 billion as of December 31, 2017 and 2016, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $95 million and $140 million as of December 31, 2017 and 2016, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $38 million and $62 million as of December 31, 2017 and 2016, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's balance sheets.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $296 million and $319 million as of December 31, 2017 and 2016, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $282 million and $305 million as of December 31, 2017 and 2016, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 14.

AEP's subsidiaries participate in one protected cell of EIS for approximately six lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. AEP's subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2017, 2016 and 2015 was $29 million, $28 million and $29 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. In January 2014, Transource Missouri (a wholly-owned subsidiary of Transource Energy) acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, construction projects, debt issuance and capital contribution. AEP has provided capital contributions to Transource Energy of $5 million and $45 million, in 2017 and 2016, respectively. AEP and the other owner of Transource Energy are required to ensure a specific equity level in Transource Missouri upon completion of projects or if a project is abandoned by the RTO. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

AEP Renewables, a wholly-owned subsidiary of Energy Supply, was formed to provide utility scale wind and solar projects whose power output is sold via long-term power purchase agreements to other utilities, cities and corporations. In 2016, AEP Renewables acquired solar projects that were funded only through participation in the AEP corporate borrowing program. As a result, management concluded that AEP Renewables was a VIE and that Energy Supply was the primary beneficiary due to its capacity to direct the most significant activities of the entity and it's equity interest could potentially be significant. In the first quarter of 2017, AEP Renewables received a capital contribution of $140 million from Energy Supply. The capital contribution gave AEP Renewables sufficient equity at risk, which resulted in the definition of a VIE no longer being met. Energy Supply continues to consolidate AEP Renewables in accordance with other applicable accounting guidance for "Consolidation" due to its controlling financial interest as the owner of AEP Renewables. See the tables below for the classification of AEP Renewables' assets and liabilities on the December 31, 2016 balance sheet.

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

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2017

	Registrant Subsidiaries				
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding
	(in millions)				
ASSETS					
Current Assets	$ 56.3	$ 102.5	$ 191.7	$ 28.7	$ 22.3

Net Property, Plant and Equipment	113.2	179.9	—	—	—
Other Noncurrent Assets	90.2	86.3	923.5 (a)	71.0 (b)	285.6 (c)
Total Assets	$ 259.7	$ 368.7	$ 1,115.2	$ 99.7	$ 307.9
LIABILITIES AND EQUITY					
Current Liabilities	$ 49.1	$ 96.5	$ 260.9	$ 47.9	$ 27.6
Noncurrent Liabilities	211.0	272.2	836.1	50.5	278.4
Equity	(0.4)	—	18.2	1.3	1.9
Total Liabilities and Equity	$ 259.7	$ 368.7	$ 1,115.2	$ 99.7	$ 307.9

(a) Includes an intercompany item eliminated in consolidation of $53.9 million.
(b) Includes an intercompany item eliminated in consolidation of $33.3 million.
(c) Includes an intercompany item eliminated in consolidation of $3.4 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2017

	Other Consolidated VIEs		
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**
	(in millions)		
ASSETS			
Current Assets	$ 926.3	$ 178.7	$ 17.4
Net Property, Plant and Equipment	—	—	323.9
Other Noncurrent Assets	6.4	—	3.1
Total Assets	$ 932.7	$ 178.7	$ 344.4
LIABILITIES AND EQUITY			
Current Liabilities	$ 872.0	$ 36.4	$ 12.4
Noncurrent Liabilities	0.7	95.2	132.0
Equity	60.0	47.1	200.0
Total Liabilities and Equity	$ 932.7	$ 178.7	$ 344.4

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2016

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**OPCo Ohio Phase-in-Recovery Funding**	**APCo Appalachian Consumer Rate Relief Funding**
	(in millions)				
ASSETS					
Current Assets	$ 60.2	$ 135.5	$ 184.8	$ 30.3	$ 20.2
Net Property, Plant and Equipment	112.0	233.9	—	—	—
Other Noncurrent Assets	89.8	116.2	1,149.4 (a)	117.1 (b)	309.0 (c)

Total Assets	$ 262.0	$ 485.6	$ 1,334.2	$ 147.4	$ 329.2
LIABILITIES AND EQUITY					
Current Liabilities	$ 26.3	$ 131.3	$ 251.9	$ 47.5	$ 27.3
Noncurrent Liabilities	235.3	354.3	1,064.2	98.6	300.6
Equity	0.4	—	18.1	1.3	1.3
Total Liabilities and Equity	$ 262.0	$ 485.6	$ 1,334.2	$ 147.4	$ 329.2

(a) Includes an intercompany item eliminated in consolidation of $61.1 million.
(b) Includes an intercompany item eliminated in consolidation of $55 million.
(c) Includes an intercompany item eliminated in consolidation of $3.7 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2016

	Other Consolidated VIEs			
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**AEP Renewables**
	(in millions)			
ASSETS				
Current Assets	$ 945.7	$ 170.6	$ 16.3	$ —
Net Property, Plant and Equipment	—	—	313.0	130.4
Other Noncurrent Assets	10.3	1.1	5.4	9.0
Total Assets	$ 956.0	$ 171.7	$ 334.7	$ 139.4
LIABILITIES AND EQUITY				
Current Liabilities	$ 877.4	$ 31.8	$ 31.7	$ 126.7
Noncurrent Liabilities	0.6	97.3	134.4	11.3
Equity	78.0	42.6	168.6	1.4
Total Liabilities and Equity	$ 956.0	$ 171.7	$ 334.7	$ 139.4

Non-Consolidated Significant Variable Interests

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2017, 2016 and 2015 were $61 million, $65 million and $93 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,	
	2017	**2016**

	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in millions)		
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	11.8	11.8	15.7	15.7
SWEPCo's Share of Obligations	—	144.3	—	91.3
Total Investment in DHLC	$ 19.4	$ 163.7	$ 23.3	$ 114.6

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2017, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2017, OVEC's outstanding indebtedness is approximately $1.4 billion. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and its subsidiaries hold a significant variable interest in OVEC. Power to control decision making that significantly impact the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors and Operating Committee of OVEC.

AEP's investment in OVEC was:

	December 31,			
	2017		2016	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in millions)		
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Ratio of OVEC Debt (a)	—	626.3	—	658.3
Total Investment in OVEC	$ 4.4	$ 630.7	$ 4.4	$ 662.7

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt is $226 million, $113.1 million and $287.2 million for the year ended December 31, 2017 and $237.6 million, $118.9 million and $301.8 million for the year-ended December 31, 2016, respectively.

The amounts of power purchased by the Registrant Subsidiaries from OVEC for the years ended December 31, 2017, 2016 and 2015 were:

Years Ended December 31,

Company	2017	2016	2015
	(in millions)		
APCo	$ 101.0	$ 88.0	$ 87.2
I&M	50.5	44.0	43.7
OPCo	128.2	111.7	110.8

The amounts above are included in Purchased Electricity for Resale on the statements of income.

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the "Allegheny Series." AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP's equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP's subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case were unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at the FERC were held in March and April 2015. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the ALJ issued an advisory Initial Decision. Additional briefing was submitted during the fourth quarter of 2015. In January 2017, the FERC issued its order on Initial Decision, adopting in part and rejecting in part the ALJ's recommendations. The FERC order included (a) a finding that the PATH Project's abandonment costs were prudently incurred, (b) a finding that the disposition of certain assets was prudent, (c) guidance regarding the future disposition of assets, (d) a reduction of PATH WV's authorized return on equity (ROE) to 8.11% prospectively only after the date of the order, (e) an adjustment of the amortization period to end December 2017, and (f) a credit for certain amounts that were deemed to be not includable in PATH-WV's formula rates.

In February 2017, the PATH Companies filed a request for rehearing of two adverse rulings in the January 2017 FERC order. The request seeks the FERC to reverse its reduction of the PATH Companies 10.4% ROE for the period after January 19, 2017 and to allow the recovery of certain education and outreach costs disallowed by the order. In February 2017, the Edison Electric Institute ("EEI") also filed a request for rehearing recommending reversal of the January 2017 FERC ordered ROE reduction and cost disallowance. The requests for rehearing by the PATH Companies and EEI are currently pending before the FERC. The requests for rehearing do not impact the recovery of costs by the PATH Companies under their formula rates or the timing of the compliance filing required by the order, which was filed in March 2017, and updated in May 2017 and August 2017. As a result of the January 2017 FERC order, PATH-WV is required to refund certain amounts that have been collected under its formula rate in its 2018 Projected Transmission Revenue Requirement. PATH-WV will refund $11.4 million, including carrying charges, related to the January 2017 order in its 2018 Projected Transmission Revenue Requirement.

AEP's investment in PATH-WV was:

	December 31,	
	2017	2016

	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 18.8	$ 18.8	$ 18.8	$ 18.8
Retained Earnings	(2.0)	(2.0)	(2.3)	(2.3)
Total Investment in PATH-WV	$ 16.8	$ 16.8	$ 16.5	$ 16.5

As of December 31, 2017, AEP's $17 million investment in PATH-WV was included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows.

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

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	**2017**	**2016**	**2015**
	(in millions)		
AEP Texas	$ 152.6	$ 142.3	$ 132.7
AEPTCo	188.9	131.1	108.4
APCo	268.8	244.2	227.5
I&M	176.0	147.7	139.5
OPCo	195.7	181.1	177.8
PSO	114.7	111.0	107.3
SWEPCo	150.7	147.0	141.4

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

	December 31,			
	2017		2016	
Company	**As Reported on the Balance Sheet**	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
	(in millions)			
AEP Texas	$ 24.2	$ 24.2	$ 22.9	$ 22.9
AEPTCo	25.1	25.1	23.0	23.0
APCo	37.0	37.0	36.7	36.7
I&M	26.8	26.8	24.2	24.2

OPCo	27.4	27.4	28.1	28.1
PSO	18.7	18.7	16.0	16.0
SWEPCo	20.8	20.8	21.8	21.8

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1, leases a 50% interest in Rockport Plant, Unit 2 and owned 100% of the Lawrenceburg Generating Station, which was sold in January 2017. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2017, 2016 and 2015 were $224 million, $229 million and $232 million. The carrying amount of I&M’s liabilities associated with AEGCo as of December 31, 2017 and 2016 was $23 million and $22 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. For additional information regarding AEGCo’s lease, see “Rockport Lease” section of Note 13. The assets and liabilities of AEGCo’s Lawrenceburg Plant have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on the balance sheet as of December 31, 2016. See “Assets and Liabilities Held for Sale” section of Note 7 for additional information.

18. PROPERTY, PLANT AND EQUIPMENT

The disclosures in this note apply to all Registrants unless indicated otherwise.

Property, Plant and Equipment is shown functionally on the face of the Registrants’ balance sheets. The following tables include the Registrants’ total plant balances as of December 31, 2017 and 2016:

December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Regulated Property, Plant and Equipment								
Generation	$ 20,406.5 (a)	$ —	$ —	$ 6,446.9	$ 4,445.9	$ —	$ 1,577.2	$ 4,624.9 (a)
Transmission	18,942.3	3,053.6	5,336.1	3,019.9	1,504.0	2,419.2	858.8	1,679.8
Distribution	19,865.9	3,718.6	—	3,763.8	2,069.3	4,626.4	2,445.1	2,095.8
Other	3,224.8	457.6	130.0	399.5	552.3	485.5	282.0	416.8
CWIP	3,972.6 (a)	834.4	1,312.7	483.0	460.2	410.1	111.3	220.7 (a)
Less: Accumulated Depreciation	16,906.7	1,399.4	170.4	3,891.1	3,011.7	2,183.9	1,393.6	2,520.5
Total Regulated Property, Plant and Equipment - Net	49,505.4	6,664.8	6,608.4	10,222.0	6,020.0	5,757.3	3,880.8	6,517.5
Nonregulated Property, Plant and Equipment - Net	756.1	160.3	1.4	23.1	30.4	9.5	5.4	114.5
Total Property, Plant and Equipment - Net	$ 50,261.5	$ 6,825.1	$ 6,609.8	$ 10,245.1	$ 6,050.4	$ 5,766.8	$ 3,886.2	$ 6,632.0

December 31, 2016	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Regulated Property, Plant and Equipment								
Generation	$ 19,703.9 (a)	$ —	$ —	$ 6,332.8	$ 4,056.1	$ —	$ 1,559.3	$ 4,607.6 (a)
Transmission	16,658.6	2,623.6	3,973.5	2,796.9	1,472.8	2,319.2	832.8	1,584.2
Distribution	18,898.2	3,527.2	—	3,569.1	1,899.3	4,457.2	2,322.4	2,020.6
Other	2,902.0	432.1	98.3	345.1	507.7	433.4	227.3	399.3

CWIP	3,072.2	(a)	385.0	981.3	390.3	654.2	221.5	148.2	113.7	(a)
Less: Accumulated Depreciation	16,101.5		1,354.4	99.6	3,631.5	2,989.9	2,115.1	1,272.7	2,411.5	
Total Regulated Property, Plant and Equipment - Net	45,133.4		5,613.5	4,953.5	9,802.7	5,600.2	5,316.2	3,817.3	6,313.9	
Nonregulated Property, Plant and Equipment - Net	505.9		167.2	1.1	23.1	27.3	9.4	5.9	115.6	
Total Property, Plant and Equipment - Net	$ 45,639.3	(b)	$ 5,780.7	$ 4,954.6	$ 9,825.8	$ 5,627.5	$ 5,325.6	$ 3,823.2	$ 6,429.5	

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

(b) Amount excludes $1.8 billion of Property, Plant and Equipment - Net classified as Assets Held for Sale on the balance sheet. See "Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)" section of Note 7 for additional information.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

	2017		2016		2015	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
		(in years)		**(in years)**		**(in years)**
Generation	2.3% - 3.7%	20 - 132	2.1% - 4.0%	35 - 132	0.4% - 3.1%	35 - 132
Transmission	1.6% - 2.7%	15 - 100	1.5% - 2.7%	15 - 100	1.4% - 2.7%	15 - 81
Distribution	2.7% - 3.7%	5 - 156	2.6% - 3.7%	7 - 156	2.5% - 3.7%	7 - 75
Other	2.3% - 9.2%	5 - 84	3.1% - 8.6%	5 - 84	2.9% - 11.8%	5 - 75

AEP Texas

	2017		2016		2015	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
		(in years)		**(in years)**		**(in years)**
Transmission	1.7%	45 - 81	1.8%	45 - 81	1.8%	45 - 81
Distribution	3.6%	7 - 70	3.3%	7 - 70	3.3%	7 - 70
Other	8.7%	5 - 50	8.3%	5 - 50	9.7%	5 - 50

AEPTCo

	2017		2016		2015	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
		(in years)		**(in years)**		**(in years)**
Transmission	1.7%	20 - 100	1.6%	20 - 100	1.4%	20 - 75

APCo

Functional Class of Property	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)
Generation	3.1%	35 - 112	3.1%	35 - 121	3.1%	35 - 121
Transmission	1.6%	15 - 68	1.5%	15 - 68	1.6%	15 - 68
Distribution	3.7%	10 - 57	3.7%	10 - 57	3.6%	10 - 57
Other	6.5%	5 - 55	6.0%	5 - 55	8.3%	5 - 55

I&M

Functional Class of Property	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)
Generation	2.4%	20 - 132	2.4%	59 - 132	2.5%	59 - 132
Transmission	1.7%	50 - 75	1.7%	50 - 75	1.7%	50 - 75
Distribution	2.7%	10 - 70	2.8%	10 - 70	2.8%	10 - 70
Other	8.4%	5 - 45	8.6%	5 - 45	11.8%	5 - 45

OPCo

Functional Class of Property	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	2.8%	5 - 57	2.8%	7 - 57	2.8%	7 - 57
Other	6.2%	5 - 50	5.9%	5 - 50	7.2%	5 - 50

PSO

Functional Class of Property	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)
Generation	2.4%	35 - 85	2.4%	35 - 85	1.7%	35 - 70
Transmission	2.2%	45 - 100	2.2%	45 - 100	1.9%	40 - 75
Distribution	2.7%	27 - 156	2.7%	27 - 156	2.5%	7 - 65
Other	7.4%	5 - 84	6.4%	5 - 84	4.6%	5 - 40

SWEPCo

Functional Class of Property	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)

Generation	2.3%	40 - 70	2.1%	40 - 70	2.2%	40 - 70
Transmission	2.3%	50 - 73	2.2%	50 - 70	2.3%	50 - 70
Distribution	2.7%	25 - 70	2.6%	25 - 65	2.6%	25 - 65
Other	7.2%	5 - 55	6.8%	5 - 51	5.5%	5 - 51

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP, AEP Texas and SWEPCo. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of AEPTCo, APCo, I&M, OPCo and PSO for 2017, 2016 and 2015.

	2017		2016		2015	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
		(in years)		**(in years)**		**(in years)**
Generation	2.4% - 5.1%	15 - 66	2.8% - 17.2%	40 - 66	2.5% - 3.4%	35 - 66
Transmission	0.2%	40	2.3%	43 - 55	2.3%	43 - 55
Distribution	2.3%	40	1.3%	40 - 50	—%	0 - 0
Other	12.1%	5 - 50 (a)	9.1%	5 - 50 (a)	2.7%	5 - 50 (a)

(a) SWEPCo's nonregulated property, plant and equipment is depreciated using the straight-line method over a range of 3 to 20 years.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO) (Applies to all Registrants except AEPTCo)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities. I&M records ARO for the decommissioning of the Cook Plant. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements

since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

As of December 31, 2017 and 2016, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.30 billion and $1.24 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2017 and 2016, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.22 billion and $1.95 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2017 and 2016 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2016	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31, 2017
			(in millions)			
AEP (a)(b)(c)(d)	$ 1,934.9	$ 90.9	$ 2.4	$ (104.5)	$ 82.0	$ 2,005.7
AEP Texas (a)(d)	25.5	1.2	—	(0.1)	0.1	26.7
APCo (a)(d)	127.1	7.0	—	(21.7)	12.6	125.0
I&M (a)(b)(d)	1,258.1	55.9	—	(0.1)	7.9	1,321.8
OPCo (d)	1.7	0.1	—	(0.1)	—	1.7
PSO (a)(d)	53.4	3.1	—	(0.5)	(2.0)	54.0
SWEPCo (a)(c)(d)	156.5	8.3	—	(0.3)	4.7	169.2

Company	ARO as of December 31, 2015	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31, 2016
			(in millions)			
AEP (a)(b)(c)(d)	$ 1,916.3	$ 91.3	$ 0.8	$ (139.9) (e)	$ 66.4	$ 1,934.9
AEP Texas (a)(d)	24.0	1.1	—	(0.1)	0.5	25.5
APCo (a)(d)	140.2	7.6	—	(35.3)	14.6	127.1
I&M (a)(b)(d)	1,253.8	55.6	—	(62.6) (e)	11.3	1,258.1
OPCo (d)	1.4	0.1	0.2	—	—	1.7
PSO (a)(d)	47.8	3.0	0.1	(1.0)	3.5	53.4
SWEPCo (a)(c)(d)	125.4	7.0	0.2	(8.3)	32.2	156.5

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.30 billion and $1.24 billion as of December 31, 2017 and 2016, respectively.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) Amount includes settlement of liabilities of $61 million associated with the sale of the Tanners Creek Plant site. See the "Tanners Creek" section of Note 7.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2017	2016	2015
		(in millions)	
AEP	$ 93.7	$ 113.2	$ 131.9
AEP Texas	6.8	9.2	6.7
AEPTCo	52.3	52.3	53.0
APCo	9.2	11.7	13.8
I&M	11.1	15.3	11.6
OPCo	6.4	6.0	8.8
PSO	0.5	6.2	8.8
SWEPCo	2.4	11.0	26.4

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2017	2016	2015
	(in millions)		
AEP	$ 48.6	$ 51.7	$ 61.3
AEP Texas	6.8	5.9	4.5
AEPTCo	20.2	15.6	17.7
APCo	5.3	6.3	6.9
I&M	6.7	7.2	5.0
OPCo	3.8	3.3	4.8
PSO	1.1	3.4	5.0
SWEPCo	2.1	6.9	14.8

Jointly-owned Electric Facilities (Applies to AEP, AEP Texas, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and non-affiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2017		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
			(in millions)		
AEP					
Conesville Generating Station, Unit 4 (a)(k)(l)	Coal	83.5%	$ 2.1	$ 4.2	$ 0.1
J.M. Stuart Generating Station (b)(k)	Coal	26.0%	—	—	—
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	343.1	5.3	214.2
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	364.8	8.9	81.6
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	589.8	7.8	406.3
Oklaunion Generating Station, Unit 1 (h)	Coal	70.3%	456.4	1.9	254.6
Turk Generating Plant (j)(n)	Coal	73.3%	1,580.4	3.2	166.6
Transmission	NA	(d)	62.7	0.3	46.1
Total			$ 3,399.3	$ 31.6	$ 1,169.5
AEP Texas					
Oklaunion Generating Station, Unit 1 (h)	Coal	54.7%	$ 350.7	$ 1.3	$ 194.1
I&M					
Rockport Generating Plant (e)(f)(g)	Coal	50.0%	$ 1,093.9	$ 28.2	$ 562.6
PSO					
Oklaunion Generating Station, Unit 1 (h)	Coal	15.6%	$ 105.7	$ 0.6	$ 60.5

SWEPCo					
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	$ 343.1	$ 5.3	$ 214.2
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	364.8	8.9	81.6
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	589.8	7.8	406.3
Turk Generating Plant (j)(n)	Coal	73.3%	1,580.4	3.2	166.6
Total			$ 2,878.1	$ 25.2	$ 868.7

			Registrant's Share as of December 31, 2016		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
			(in millions)		
AEP					
Conesville Generating Station, Unit 4 (a)(k)(l)	Coal	43.5%	$ 0.1	$ 1.3	$ —
J.M. Stuart Generating Station (b)(k)	Coal	26.0%	—	0.8	—
Wm. H. Zimmer Generating Station (c)(k)(m)	Coal	25.4%	—	0.3	—
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	334.8	5.0	207.5
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	362.4	3.7	73.5
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	586.4	5.7	399.5
Oklaunion Generating Station, Unit 1 (h)	Coal	70.3%	454.8	1.3	246.0
Turk Generating Plant (j)	Coal	73.3%	1,657.3	0.2	138.5
Transmission	NA	(d)	62.4	0.5	45.1
Total			$ 3,458.2	$ 18.8	$ 1,110.1
AEP Texas					
Oklaunion Generating Station, Unit 1 (h)	Coal	54.7%	$ 349.6	$ 0.9	$ 186.5
I&M					
Rockport Generating Plant (e)(f)(g)	Coal	50.0%	$ 936.1	$ 125.8	$ 535.1
PSO					
Oklaunion Generating Station, Unit 1 (h)	Coal	15.6%	$ 105.2	$ 0.5	$ 59.4
SWEPCo					
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	$ 334.8	$ 5.0	$ 207.5
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	362.4	3.7	73.5
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	586.4	5.7	399.5
Turk Generating Plant (j)	Coal	73.3%	1,657.3	0.2	138.5
Total			$ 2,940.9	$ 14.6	$ 819.0

(a) Operated by AGR.
(b) Operated by Dayton Power & Light Company, a non-affiliated company.
(c) Operated by Dynegy Corporation, a non-affiliated company.
(d) Varying percentages of ownership.
(e) Operated by I&M.
(f) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a non-affiliated company. See the "Rockport Lease" section of Note 13.
(g) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.

(h) Operated by PSO, which owns 15.6%. Also jointly-owned (54.7%) by AEP Texas and various non-affiliated companies. See the "Impairments" section of Note 7.
(i) Operated by CLECO, a non-affiliated company.
(j) Operated by SWEPCo.
(k) Conesville Generating Station, Unit 4 was impaired as of September 30, 2016. J.M. Stuart Generating Station and Wm. H. Zimmer Generating Station were impaired as of November 30, 2016. See the "Impairments" section of Note 7.
(l) In accordance with the Asset Purchase Agreement between AGR and Dynegy Corporation dated February 2017, AGR acquired Dynegy Corporation's 40% ownership interest in Conesville Generating Station, Unit 4. Subsequent to this transaction, AGR's ownership percentage in Conesville Generating Station, Unit 4 is 83.5%.
(m) In accordance with the Asset Purchase Agreement between AGR and Dynegy Corporation dated February 2017, Dynegy Corporation acquired AGR's 25.4% ownership interest in Wm. H. Zimmer Generating Station. Subsequent to this transaction, AGR has no ownership interest in Wm. H. Zimmer Generating Station. See the "Dispositions" section of Note 7.
(n) In December 2017, SWEPCo recorded a $15 million pretax impairment related to the Louisiana jurisdictional share of Turk Plant. Amount reflects the impact of the impairment. See the "Impairments" section of Note 7.
NA Not applicable.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant is as follows:

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
March 31, 2017								
Total Revenues	$ 3,933.3	$ 343.6	$ 152.7	$ 792.8	$ 560.5	$ 746.1	$ 304.1	$ 401.3
Operating Income	1,097.1	83.2	90.4	220.2	118.7	150.7	20.8	53.7
Net Income	594.2	33.3	57.0	110.6	68.4	86.2	4.8	17.3
Earnings Attributable to Common Shareholders	592.2	NA	NA	NA	NA	NA	NA	16.3
June 30, 2017								
Total Revenues	$ 3,576.5	$ 389.5	$ 229.4	$ 675.3	$ 467.3	$ 663.9	$ 344.7	$ 424.7
Operating Income	744.7	109.7	165.4	127.4	35.2	119.6	46.1	75.0
Net Income	376.2	49.0	107.4	52.1	10.5	62.3	20.4	25.1
Earnings Attributable to Common Shareholders	375.0	NA	NA	NA	NA	NA	NA	24.5
September 30, 2017								
Total Revenues	$ 4,104.7	$ 431.2	$ 167.3	$ 719.3	$ 557.7	$ 742.0	$ 442.8	$ 517.6
Operating Income	986.5	129.7	95.1	173.0	115.1	154.5	86.8	137.0
Net Income	556.7	64.3	59.9	86.0	64.9	82.6	46.2	84.1
Earnings Attributable to Common Shareholders	544.7	NA	NA	NA	NA	NA	NA	73.1
December 31, 2017								
Total Revenues	$ 3,810.4	$ 374.1	$ 173.8	$ 746.8	$ 535.7	$ 731.9	$ 335.6	$ 436.3
Operating Income	742.2	97.1	96.9	174.9	84.3	145.4	21.2	42.0
Net Income	401.8	163.9	61.8	82.6	42.9	92.8	0.6	11.0

Earnings Attributable to Common Shareholders	400.7	NA	NA	NA	NA	NA	NA	10.8

NA Not applicable.

Quarterly Periods Ended:	AEP		AEP Texas		AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)					
March 31, 2016										
Total Revenues	$ 4,044.9		$ 330.5		$ 79.6	$ 820.0	$ 532.7	$ 763.6	$ 274.3	$ 379.0
Operating Income	892.9		82.4		34.8	244.4	115.8	134.0	35.8	51.4
Income from Continuing Operations	503.1		35.0		—	—	—	—	—	—
Income (Loss) from Discontinued Operations, Net of Tax	—		(1.3)	(c)	—	—	—	—	—	—
Net Income	503.1		33.7		25.8	126.3	74.7	70.2	15.7	24.5
June 30, 2016										
Total Revenues	$ 3,892.9		$ 365.0		$ 153.1	$ 673.5	$ 522.4	$ 730.8	$ 300.2	$ 427.0
Operating Income	866.2		103.4		108.1	158.3	94.8	138.6	59.0	85.9
Income from Continuing Operations	506.4		49.7		—	—	—	—	—	—
Income (Loss) from Discontinued Operations, Net of Tax	(2.5)	(a)	(0.7)	(c)	—	—	—	—	—	—
Net Income	503.9		49.0		74.8	73.4	51.3	74.6	28.9	44.3
September 30, 2016										
Total Revenues	$ 4,652.2		$ 403.9		$ 125.3	$ 778.2	$ 597.6	$ 871.3	$ 401.7	$ 539.7
Operating Income (Loss)	(1,127.9)	(b)	112.4		76.4	204.4	131.4	171.6	98.4	147.4
Income (Loss) from Continuing Operations	(764.2)	(b)	55.5		—	—	—	—	—	—
Income (Loss) from Discontinued Operations, Net of Tax	—		(47.4)	(c)	—	—	—	—	—	—
Net Income (Loss)	(764.2)	(b)	8.1		52.4	104.1	75.4	99.9	52.8	84.4
December 31, 2016										
Total Revenues	$ 3,790.1		$ 362.0		$ 120.0	$ 729.5	$ 514.9	$ 588.2	$ 273.6	$ 402.3
Operating Income	575.9		81.4		60.8	136.2	39.6	64.3	5.5	36.4
Income from Continuing Operations	375.2		55.2		—	—	—	—	—	—
Income from Discontinued Operations, Net of Tax	—		0.6	(c)	—	—	—	—	—	—
Net Income	375.2		55.8		39.7	65.3	38.5	37.5	2.6	16.5

(a) Includes final accounting adjustment for sale of AEPRO (see Note 7).
(b) Includes impairments for certain merchant generation assets (see Note 7).
(c) Includes the transfer of the Wind Farms (see Note 7).

AEP

The unaudited quarterly financial information relating to Common Shareholders is as follows:

	2017 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders	$ 592.2	$ 375.0	$ 544.7	$ 400.7
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.20	0.76	1.11	0.81
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.20	0.76	1.10	0.81

	2016 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings (Loss) Attributable to AEP Common Shareholders	$ 501.2	$ 502.1	$ (765.8) (a)	$ 373.4
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.02	1.03	(1.56) (a)	0.76
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders from Discontinued Operations (c)	—	(0.01)	—	—
Total Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders (b)	1.02	1.02	(1.56) (a)	0.76
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.02	1.03	(1.56) (a)	0.76
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders from Discontinued Operations (c)	—	(0.01)	—	—
Total Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders (b)	1.02	1.02	(1.56) (a)	0.76

(a) Relates to impairments for certain merchant generation assets (see Note 7).
(b) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(c) Relates to final accounting adjustment for sale of AEPRO (see Note 7).

20. GOODWILL AND OTHER INTANGIBLE ASSETS

The disclosures in this note apply to AEP only.

Goodwill

The changes in AEP's carrying amount of goodwill for the years ended December 31, 2017 and 2016 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2015	$ 37.1	$ 15.4	$ 52.5
Impairment Losses	—	—	—
Balance as of December 31, 2016	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2017	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2017 and 2016, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Amortization of intangible assets was $2 million and $3 million for the years ended December 31, 2016 and 2015, respectively. Acquired intangible assets were fully amortized as of December 31, 2016. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31, 2016	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)	
Acquired Customer Contracts	5	$ 58.3	$ 58.3

AEP Transmission Company, LLC

Offers to Exchange

$125,030,000 aggregate principal amount of its 3.10% Senior Notes, Series F due 2026 and $500,000,000 aggregate principal amount of its 3.75% Senior Notes, Series I due 2047, each of which have been registered under the Securities Act of 1933, as amended,

for any and all of its outstanding

3.10% Senior Notes, Series D due 2026 and 3.75% Senior Notes, Series H due 2047, respectively

PROSPECTUS

April 6, 2018