Fiesta Restaurant Group, Inc.
Form PREC14A
April 13, 2017

PRELIMINARY COPY SUBJECT TO COMPLETION — DATED APRIL 13, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 14A

Proxy Statement Pursuant to Section 14(a)
of the Securities Exchange Act of 1934
(Amendment No.)

Filed by the Registrant

Filed by a Party other than the Registrant

Check the appropriate box:

Preliminary Proxy Statement
Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))
Definitive Proxy Statement
Definitive Additional Materials
Soliciting Material under §240.14a-12

FIESTA RESTAURANT GROUP, INC.

(Name of Registrant as Specified in its Charter)

(Name of Person(s) Filing Proxy Statement if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

No fee required.
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(1) Title of each class of securities to which transaction applies:

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(3) Filing Party:

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PRELIMINARY COPY SUBJECT TO COMPLETION —DATED APRIL 13, 2017

2017

Annual Meeting of Shareholders

Notice and Proxy Statement

[ ], 2017

[ ] a.m.

FIESTA RESTAURANT GROUP, INC.

14800 Landmark Boulevard, Suite 500

Dallas, TX 75254

[ ], 2017

Deal Fellow Shareholders,

We are pleased to invite you to attend the annual meeting of shareholders of Fiesta Restaurant Group, Inc. to be held at [ ] on [ ], [ ], 2017, at [ ] A.M. ([ ]). The formal notice of annual meeting appears on the next page.

Your vote will be especially important at this annual meeting. As you may have heard certain individuals and funds who purchased shares of Fiesta Restaurant Group in the last twelve months (collectively, the "*Dissident Group*") notified us of their intent to nominate three nominees for election as a director at the annual meeting in opposition to the nominees recommended by the board of directors. However, as of April 12, 2017, the Dissident Group has publicly withdrawn one of their nominees and has now indicated their intent to nominate two director nominees for election at the 2017 Annual Meeting in opposition to two of the nominees recommended by the board of directors.

We strongly urge you to read the accompanying proxy statement carefully and vote FOR the nominees proposed by the board of directors, and in accordance with the board's recommendations on the other proposals, by using the enclosed **WHITE** proxy card. If you have voted using the proxy card sent to you by the Dissident Group, you can subsequently revoke it by using the **WHITE** proxy card to vote. Only your latest-dated vote will count—any prior proxy card may be revoked at any time prior to the annual meeting as described in the accompanying proxy statement.

We look forward to greeting personally those shareholders who are able to be present at the meeting. However, regardless of whether you plan to be with us at the meeting, it is important that your voice be heard. Accordingly, we request that you vote on the **WHITE** proxy card by telephone, by Internet or by signing, dating and returning the **WHITE** proxy card in the postage-paid envelope provided.

If you have any questions or require any assistance with voting your **WHITE** proxy card, please contact our proxy solicitation firm MacKenzie Partners, Inc. at:

105 Madison Avenue

New York, New York 10016

proxy@mackenziepartners.com

Call Collect: (212) 929-5500

or

Toll-Free: (800) 322-2885

Email: fiesta@mackenziepartners.com

Very truly yours,

Stacey Rauch,	Rich Stockinger
Chairman of the Board of Directors	*Chief Executive Officer and President*

FIESTA RESTAURANT GROUP, INC.
14800 Landmark Boulevard, Suite 500
Dallas, Texas 75254

To the Shareholders of Fiesta Restaurant Group, Inc.:

You are invited to attend the 2017 Annual Meeting of Shareholders, which we refer to as the "*2017 Annual Meeting*", of FIESTA RESTAURANT GROUP, INC., a Delaware corporation, which we refer to as "*we*", "*us*", "*our*", the "*Company*" and "*Fiesta Restaurant Group*", at [ ] on [ ], [ ], 2017, at [ ] A.M. ([ ]), for the following purposes:

(1) To elect three directors of the Company as Class II directors to serve for a term of three years and until their successors have been duly elected and qualified;

(2) To adopt, on an advisory basis, a non-binding resolution approving the compensation of the Company's Named Executive Officers, as described in the Proxy Statement under "Executive Compensation";

(3) To approve the Fiesta Restaurant Group, Inc. 2012 Stock Incentive Plan, as amended, for purposes of complying with Section 162(m) of the Internal Revenue Code of 1986, as amended;

(4) To approve an amendment to the Company's Restated Certificate of Incorporation to implement a majority voting standard in uncontested elections of directors;

(5) To ratify the appointment of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for the 2017 fiscal year; and

(6) To consider and act upon such other matters as may properly come before the 2017 Annual Meeting.

Only shareholders of record at the close of business on [ ], 2017, which we refer to as the "*record date*", are entitled to receive notice of, and to vote at, the 2017 Annual Meeting, and at any adjournment or postponements thereof. Such shareholders are urged to submit an enclosed **WHITE** proxy card, even if your shares were sold after such date. If your brokerage firm, bank, broker-dealer or other similar organization is the holder of record of your shares (i.e., your shares are held in "street-name"), you will receive voting instructions from the holder of record. You must follow these

instructions in order for your shares to be voted. We recommend that you instruct your broker or other nominee, by following those instructions, to vote your shares for the enclosed **WHITE** proxy card. A list of our shareholders as of the close of business on [ ], 2017 will be available for inspection during business hours for ten days prior to the 2017 Annual Meeting at our principal executive offices located at 14800 Landmark Boulevard, Suite 500, Dallas, TX 75254.

The accompanying Proxy Statement provides detailed information about the matters to be considered at the 2017 Annual Meeting. It is important that your voice be heard and your shares be represented at the 2017 Annual Meeting whether or not you are personally able to attend. Even if you plan to attend the 2017 Annual Meeting, we hope that you will read the Proxy Statement and the voting instructions on the enclosed **WHITE** proxy card. **We urge you to vote TODAY by completing, signing and dating the WHITE proxy card and mailing it in the enclosed, postage pre-paid envelope, or vote by telephone or the Internet by following the instructions on the WHITE proxy card.** If your shares are not registered in your own name and you would like to attend the 2017 Annual Meeting, please ask the broker, bank or other nominee that holds the shares to provide you with evidence of your record date share ownership.

As you may know, JCP Investment Management, LLC, JCP Investment Partnership, LP, JCP Single-Asset Partnership, LP, JCP Investment Partners, LP, JCP Investment Holdings, LLC, James C. Pappas, BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., Bradley L. Radoff, Bandera Master Fund L.P., Bandera Partners LLC, Gregory Bylinsky, Jefferson Gramm, Lake Trail Managed Investments LLC, Lake Trail Capital LP, Lake Trail Capital GP LLC, Thomas W. Purcell, Jr., Joshua E. Schechter, John Morlock and Alan Vituli, including each of their affiliates and associates (collectively, the "*Dissident Group*"), purchased shares of Fiesta Restaurant Group in the last twelve months and notified the Company of their intent to nominate three nominees for election as a director of the Company at the 2017 Annual Meeting in opposition to the nominees recommended by the board of directors. However, as of April 12, 2017, the Dissident Group has publicly withdrawn one of their nominees and has now indicated their intent to nominate two director nominees for election at the 2017 Annual Meeting in opposition to two of the nominees recommended by the board of directors. You may receive proxy solicitation materials from the Dissident Group. The Company is not responsible for the accuracy of any information provided by or relating to the Dissident Group or its nominee contained in solicitation materials filed or disseminated by or on behalf of the Dissident Group or any other statements that the Dissident Group may make. **The board does NOT endorse the Dissident Group nominees and strongly and unanimously recommends that you NOT sign or return any proxy card sent to you by the Dissident Group. If you have previously voted using a proxy card sent to you by the Dissident Group, you can subsequently revoke that proxy by following the instructions on the enclosed WHITE proxy card to vote over the Internet or by telephone or by completing, signing and dating the proxy card and mailing it in the postage pre-paid envelope provided. Only your latest dated proxy will count. Any proxy may be revoked at any time prior to its exercise at the 2017 Annual Meeting as described in the accompanying Proxy Statement.**

THE BOARD UNANIMOUSLY RECOMMENDS VOTING

FOR THE ELECTION OF EACH OF THE BOARD'S NOMINEES ON PROPOSAL 1 AND

FOR PROPOSALS 2, 3, 4 AND 5 USING THE ENCLOSED WHITE PROXY CARD.

THE BOARD URGES YOU NOT TO SIGN, RETURN OR VOTE ANY PROXY CARD SENT TO YOU

BY THE DISSIDENT GROUP.

You are cordially invited to attend the 2017 Annual Meeting in person. In accordance with our security procedures, all persons attending the 2017 Annual Meeting will be required to present a form of government-issued picture identification. If you hold your shares in "street-name", you must also provide proof of ownership (such as recent brokerage statement). If you are a holder of record and attend the 2017 Annual Meeting, you may vote by ballot in person even if you have previously returned your proxy card. If you hold your shares in "street-name" and wish to vote in person, you must provide a "legal proxy" from your bank or broker.

Please note that, even if you plan to attend the 2017 Annual Meeting, we recommend that you vote using the enclosed **WHITE** proxy card prior to the 2017 Annual Meeting to ensure that your shares will be represented.

Regardless of the number of shares of common stock of the Company that you own, your vote is important. Thank you for your continued support, interest and investment in Fiesta Restaurant Group.

Very truly yours,

By order of the Board of Directors,

JOSEPH A. ZIRKMAN,
Senior Vice President, General Counsel & Secretary

Dallas, Texas

[ ], 2017

IMPORTANT

TO ASSURE THAT YOUR SHARES ARE REPRESENTED AT THE 2017 ANNUAL MEETING, WE URGE YOU TO COMPLETE, DATE AND SIGN THE ENCLOSED **WHITE** PROXY CARD AND MAIL IT PROMPTLY IN THE POSTAGE-PAID ENVELOPE PROVIDED, OR VOTE BY TELEPHONE OR THE INTERNET AS INSTRUCTED ON THE **WHITE** PROXY CARD, WHETHER OR NOT YOU PLAN TO ATTEND THE 2017 ANNUAL MEETING. YOU CAN REVOKE YOUR PROXY AT ANY TIME BEFORE THE PROXIES YOU APPOINTED CAST YOUR VOTES.

If you have any questions or need any assistance in voting your shares, please contact our proxy solicitor:

105 Madison Avenue

New York, New York 10016

proxy@mackenziepartners.com

Call Collect: (212) 929-5500

or

Toll-Free: (800) 322-2885

Email: fiesta@mackenziepartners.com

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE 2017 ANNUAL MEETING TO BE HELD ON [ ], 2017: THE PROXY STATEMENT FOR THE 2017 ANNUAL MEETING AND THE ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR-ENDED JANUARY 1, 2017 ARE AVAILABLE FREE OF CHARGE ON OUR WEBSITE AT WWW.FRGI.COM.

The Notice of Annual Meeting of Shareholders and the attached Proxy Statement are first being made available to shareholders of record as of [ ], 2017 on or about [ ], 2017.

FIESTA RESTAURANT GROUP, INC.

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PRELIMINARY COPY SUBJECT TO COMPLETION — DATED APRIL 13, 2017

FIESTA RESTAURANT GROUP, INC.
14800 Landmark Boulevard, Suite 500
Dallas, Texas 75254

PROXY STATEMENT FOR ANNUAL MEETING OF SHAREHOLDERS
[ ], 2017

This Proxy Statement is furnished in connection with the solicitation of proxies by the board of directors of FIESTA RESTAURANT GROUP, INC., a Delaware corporation, to be used at the Annual Meeting of Shareholders, which we refer to as the "*meeting*", of the Company which will be held at [ ] on [ ], 2017, at [ ] A.M. (CDT), and at any adjournment or adjournments thereof. Only shareholders of record at the close of business on [ ], 2017, which we refer to as the "*record date*", will be entitled to vote at the 2017 Annual Meeting. This Proxy Statement, the enclosed **WHITE** proxy card, and the Annual Report on Form 10-K for the fiscal year ended January 1, 2017 are first being mailed to shareholders of record as of [ ], 2017 on or about [ ], 2017.

Holders of our common stock at the close of business on [ ], 2017 will be entitled to vote at the 2017 Annual Meeting. As of the date of this Proxy Statement, [ ] shares of our common stock, $0.01 par value per share, were outstanding and entitled to vote. Shareholders are entitled to one vote for each share of common stock held. A majority, or [ ], of these shares, present in person or represented by proxy at the 2017 Annual Meeting, will constitute a quorum for the transaction of business.

The Notice of Annual Meeting of Shareholders, this Proxy Statement, the enclosed **WHITE** proxy card and the Annual Report on Form 10-K for the Company's fiscal year-ended January 1, 2017 are also available at *www.frgi.com*.

All references in this Proxy Statement to "*Fiesta Restaurant Group*", the "*Company*", "*we*", "*us*" and "*our*" refer to Fiesta Restaurant Group, Inc. References to the "*board of directors*" or "*board*" refer to the board of directors of Fiesta Restaurant Group.

QUESTIONS AND ANSWERS ABOUT THE 2017 ANNUAL MEETING

Why am I receiving this Proxy Statement?

At the 2017 Annual Meeting, the Company asks you to vote on six proposals:

Proposal 1: to elect three directors of the Company, each to hold office for a three-year term and until his successor has been duly elected and qualified;

Proposal 2: to adopt, on an advisory basis, a non-binding resolution approving the compensation of the Company's Named Executive Officers, as described in the Proxy Statement under "Executive Compensation";

Proposal 3: to approve the Fiesta Restaurant Group, Inc. 2012 Stock Incentive Plan, as amended, for purposes of complying with Section 162(m) of the Internal Revenue Code of 1986, as amended;

Proposal 4: to approve an amendment to the Company's Restated Certificate of Incorporation to implement a majority voting standard in uncontested elections of directors;

Proposal 5: to ratify the appointment of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for the 2017 fiscal year; and

Proposal 6: to consider and act upon such other matters as may properly come before the 2017 Annual Meeting.

The board may also ask you to participate in the transaction of any other business that is properly be brought before the 2017 Annual Meeting in accordance with the provisions of our Restated Certificate of Incorporation, as amended (the "*Restated Certificate of Incorporation*") and Amended and Restated Bylaws (the "*Bylaws*").

You are receiving this Proxy Statement as a shareholder of the Company as of [ ], 2017, the record date for purposes of determining the shareholders entitled to receive notice of and vote at the 2017 Annual Meeting. As further described below, we request that you promptly use the enclosed **WHITE** proxy card to vote, by Internet, by telephone or by mail, in the event you desire to express your support of or opposition to the proposals.

THE BOARD UNANIMOUSLY RECOMMENDS VOTING

FOR THE ELECTION OF EACH OF THE BOARD'S NOMINEES ON PROPOSAL 1 AND

FOR PROPOSALS 2, 3, 4 AND 5 USING THE ENCLOSED WHITE PROXY CARD.

THE BOARD URGES YOU NOT TO SIGN, RETURN OR VOTE ANY PROXY CARD SENT TO YOU

BY THE DISSIDENT GROUP, EVEN AS A PROTEST VOTE AS ONLY YOUR LATEST DATE PROXY CARD WILL BE COUNTED.

When will the 2017 Annual Meeting be held?

The 2017 Annual Meeting is scheduled to be held at [ ] A.M. (CDT), on [ ], [ ], 2017, at [ ].

Who is soliciting my vote?

In this Proxy Statement, the board is soliciting your vote.

How does the board recommend that I vote?

The board unanimously recommends that you vote by proxy using the **WHITE** proxy card with respect to the proposals, as follows:

FOR the election of all three board nominees set forth on the **WHITE** proxy card;

FOR on an advisory basis, the approval of the non-binding resolution on the compensation of the Company's Named Executive Officers as described in the Proxy Statement under "Executive Compensation";

FOR the approval of the Fiesta Restaurant Group, Inc. 2012 Stock Incentive Plan, as amended, which we refer to as the "*Plan*" for purposes of complying with Section 162(m) of the Internal Revenue Code of 1986, as amended, which we refer to as the "*Code*";

FOR the approval of an amendment to our Restated Certificate of Incorporation to implement a majority voting standard in uncontested elections of directors; and

FOR the ratification of the appointment of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for the 2017 fiscal year.

Why is the board recommending FOR Proposals 1, 2, 3, 4 and 5?

We describe all proposals and the board's reasons for supporting Proposals 1, 2, 3, 4 and 5 in detail beginning at page 14 of this Proxy Statement.

Who can vote?

Holders of our common stock at the close of business on [ ], 2017, the record date, may vote at the 2017 Annual Meeting. At the close of business on that date, we had [ ] shares of our common stock outstanding and entitled to vote.

As of the date of this Proxy Statement, there are [ ] shares of our common stock outstanding, each entitled to one vote.

How do I vote if I am a record holder?

You can vote by attending the 2017 Annual Meeting and voting in person, or you can vote by proxy. If you are the record holder of your stock, you can vote in the following four ways:

By Internet: You may vote by submitting a proxy over the Internet. Please refer to the **WHITE** proxy card or voting instruction form provided to you by your broker for instructions of how to vote by Internet.

By Telephone: Shareholders located in the United States that receive proxy materials by mail may vote by submitting a proxy by telephone by calling the toll-free telephone number on the **WHITE** proxy card or voting instruction form and following the instructions.

By Mail: If you received proxy materials by mail, you can vote by submitting a proxy by mail by marking, dating, signing and returning the **WHITE** proxy card in the postage-paid envelope.

In Person at the 2017 Annual Meeting: If you attend the 2017 Annual Meeting, you may deliver your completed **WHITE** proxy card in person or you may vote by completing a ballot, which we will provide to you at the 2017 Annual Meeting. You are encouraged to complete, sign and date the **WHITE** proxy card and mail it in the enclosed postage pre-paid envelope regardless of whether or not you plan to attend the 2017 Annual Meeting.

How do I vote if my common shares are held in "street name"?

If you hold your shares beneficially in street name through a nominee (such as a bank or broker), you may be able to complete your proxy and authorize your vote by proxy by telephone or the Internet as well as by mail. You should follow the instructions you receive from your nominee to vote these shares.

If you do not provide voting instructions to your bank, broker, trustee or other nominee holding shares of our common stock for you, your shares will not be voted with respect to any proposal, as we do not believe any of the proposals qualify for discretionary voting treatment by a broker. We therefore encourage you to provide voting instructions on a proxy card or a provided voting instruction form to the bank, broker, trustee or other nominee that holds your shares by carefully following the instructions provided in their notice to you.

How many votes do I have?

Shareholders are entitled to one vote per proposal for each share of common stock held.

How will my shares of common stock be voted?

The shares of common stock represented by any proxy card which is properly executed and received by the Company prior to or at the 2017 Annual Meeting will be voted in accordance with the specifications you make thereon. Where a choice has been specified on the **WHITE** proxy card with respect to the proposals, the shares represented by the **WHITE** proxy will be voted in accordance with the specifications. If you return a validly executed **WHITE** proxy card without indicating how your shares should be voted on a matter and you do not revoke your proxy, your proxy will be voted: **FOR** the election of the three named director nominees as Class II directors set forth on the **WHITE** proxy card (Proposal 1); **FOR**, on an advisory basis, the approval of the non-binding resolution on the compensation of the Company's Named Executive Officers as described in the Proxy Statement under "Executive Compensation," (Proposal 2); **FOR** the approval of the Fiesta Restaurant Group, Inc. 2012 Stock Incentive Plan, as amended, for purposes of complying with Section 162(m) of the Internal Revenue Code of 1986, as amended, (Proposal 3); **FOR** the approval of an amendment to our Restated Certificate of Incorporation to implement a majority voting standard in uncontested elections of directors (Proposal 4); and **FOR** the ratification of the appointment of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for the 2017 fiscal year (Proposal 5).

What vote is required with respect to the proposals?

Proposal 1, regarding the election of three directors to our board, will require approval of a plurality of the votes cast, meaning that the director nominees receiving the highest numbers of “for” votes of the shares entitled to be voted for them, up to the number of directors to be elected by such shares, will be elected. As a result, the three director nominees receiving the most “for” votes at the 2017 Annual Meeting will be elected. The enclosed **WHITE** proxy card enables a shareholder to vote “FOR” or “WITHHOLD” from voting as to each person nominated by the board.

Proposals 2, 3, 5, and 6 will be decided by the affirmative vote of a majority of the votes cast. The enclosed **WHITE** proxy card enables a shareholder to vote “FOR,” “AGAINST” or “ABSTAIN” on these proposals. Each of Proposals 2, 3, 5, and 6 will pass if the total votes cast “for” a given proposal exceed the total number of votes cast “against” such given proposal.

Proposal 4 will be decided by the affirmative vote of 66 2/3% of the outstanding shares of our common stock.

What is the effect of abstentions and broker non-votes on voting?

Abstentions and broker “non-votes” are included in the determination of the number of shares present at the 2017 Annual Meeting for quorum purposes. Abstentions will count as a vote against the proposals, other than for the election of directors. Abstentions will not have an effect on the election of directors because directors are elected by a plurality of the votes cast. Broker “non-votes” are not counted in the tabulations of the votes cast or present at the 2017 Annual Meeting and entitled to vote on any of the proposals and therefore will have no effect on the outcome of the proposals. A broker “non-vote” occurs when a nominee holding shares for a beneficial owner does not vote on a particular proposal because the nominee does not have discretionary voting power with respect to that item and has not received instructions from the beneficial owner. We do not anticipate any of the proposals presented at the 2017 Annual Meeting will allow nominees to exercise discretionary voting power.

What happens if proposal 4, which would implement majority voting, receives a majority of the votes cast but not a vote of 66 2/3% of the outstanding shares of our common stock?

Our Restated Certificate of Incorporation contains provisions which incorporate the plurality voting standard. In order to implement majority voting, an amendment to the Restated Certificate of Incorporation is required and such amendment requires the vote of 66 2/3% of the outstanding shares of our common stock. If this threshold is not met, then the amendment to the Restated Certificate of Incorporation will not be adopted. However, if the proposal receives the support of a majority of the votes cast but less than 66 2/3% of the outstanding shares of our common stock, then the board will adopt a policy whereby, if a director nominee is elected but receives more votes withholding support than votes FOR, the director must offer his or her resignation, to the board.

If I have already voted by proxy against the proposals, can I still change my mind?

Yes. To change your vote by proxy, simply sign, date and return the enclosed **WHITE** proxy card or voting instruction form in the accompanying postage-paid envelope, or vote by proxy by telephone or via the Internet in accordance with the instructions in the proxy card or voting instruction form. We strongly urge you to vote by proxy FOR Proposals 1, 2, 3, 4 and 5. Only your latest dated proxy will count at the 2017 Annual Meeting.

Will my shares be voted if I do nothing?

If your shares of our common stock are registered in your name, you must sign and return a proxy card in order for your shares to be voted, unless you vote over the Internet or by telephone or attend the 2017 Annual Meeting and vote in person.

If your shares of common stock are held in “street name,” that is, held for your account by a broker, bank or other nominee, and you do not instruct your broker or other nominee how to vote your shares, then, because all of the proposals are “non-routine matters,” your broker or other nominee would not have discretionary authority to vote your shares on the proposals. If your shares of our common stock are held in “street name,” your broker, bank or nominee has enclosed a proxy card or voting instruction form with this Proxy Statement. We strongly encourage you to authorize your broker or other nominee to vote your shares by following the instructions provided on the proxy card or voting instruction form.

Please return your proxy card or voting instruction form to your broker or other nominee by proxy, simply sign, date and return the enclosed proxy card or voting instruction form in the accompanying postage-paid envelope, or vote by proxy by telephone or via the Internet in accordance with the instructions in the proxy card or voting instruction form.

Please contact the person responsible for your account to ensure that a proxy card or voting instruction form is voted on your behalf.

We strongly urge you to vote by proxy FOR Proposals 1, 2, 3, 4 and 5 by signing, dating and returning the enclosed WHITE proxy card today in the envelope provided. You may also vote by proxy over the Internet using the Internet address on the proxy card or by telephone using the toll-free number on the proxy card. If your shares are held in "street name," you should follow the instructions on your proxy card or voting instruction form provided by your broker or other nominee and provide specific instructions to your broker or other nominee to vote as described above.

What constitutes a quorum?

A majority of the outstanding shares of common stock, present in person or represented by proxy, will constitute a quorum for the transaction of business at the 2017 Annual Meeting. Votes withheld, abstentions and broker non-votes will be counted as present or represented for purposes of determining the presence or absence of a quorum for this meeting. In the absence of a quorum, the 2017 Annual Meeting may be adjourned by a majority of the votes entitled to be cast represented either in person or by proxy.

Has the Company received notice from one or more shareholders that they are intending to nominate director candidates at the 2017 Annual Meeting?

Yes. The Dissident Group has indicated that it beneficially owns an aggregate of [ ] shares of our common stock (representing approximately [ ]% of our outstanding common stock), and has delivered notice to the Company of its intention to nominate two director candidates for election to the board at the 2017 Annual Meeting to serve a three-year term until their successors are elected and qualified.

Whom should I call if I have questions about the 2017 Annual Meeting?

If you have any questions or require any assistance with voting your shares, or if you need additional copies of the proxy materials, please contact:

105 Madison Avenue

New York, New York 10016

proxy@mackenziepartners.com

Call Collect: (212) 929-5500

or

Toll-Free: (800) 322-2885

Email: fiesta@mackenziepartners.com

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE 2017 ANNUAL MEETING TO BE HELD ON [ ], 2017: THE PROXY STATEMENT FOR THE 2017 ANNUAL MEETING AND THE ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR-ENDED JANUARY 1, 2017 ARE AVAILABLE FREE OF CHARGE ON OUR WEBSITE AT WWW.FRGI.COM.

ANNUAL MEETING PROCEDURES

Annual Meeting Admission

Only Fiesta Restaurant Group shareholders or their duly authorized and constituted proxies may attend the 2017 Annual Meeting. Proof of ownership of our common stock must be presented in order to be admitted to the 2017 Annual Meeting. If your shares are held in the name of a bank, broker or other holder of record and you plan to attend the 2017 Annual Meeting in person, you must bring a brokerage statement, the proxy card mailed to you by your bank or broker or other proof of ownership as of the close of business on [ ], 2017, the record date, to be admitted to the 2017 Annual Meeting. Otherwise, proper documentation of a duly authorized and constituted proxy must be presented. This proof can be: a brokerage statement or letter from a broker, bank or other nominee indicating ownership on the record date, a proxy card, or a valid, legal proxy provided by your broker, bank or other nominee.

After the chairman of the meeting opens the 2017 Annual Meeting, further entry will be prohibited. No cameras, recording equipment, electronic devices, large bags, briefcases or packages will be permitted in the 2017 Annual Meeting, the use of mobile phones during the 2017 Annual Meeting is also prohibited. All persons attending the 2017 Annual Meeting will be required to present a valid government-issued picture identification, such as a driver's license or passport, to gain admittance to the 2017 Annual Meeting.

Who Can Vote, Outstanding Shares

Holders of record of our common stock at the close of business on [ ], 2017 may vote at the 2017 Annual Meeting. At the close of business on that date, we had [ ] shares of our common stock outstanding and entitled to vote. A majority, or [ ], of these shares, present in person or represented by proxy at this meeting, will constitute a quorum for the transaction of business.

As of the date of this Proxy Statement, there are [ ] shares of our common stock outstanding, each entitled to one vote.

Voting Procedures

You can vote by attending the 2017 Annual Meeting and voting in person, or you can vote by proxy. If you are the record holder of your stock, you can vote in the following four ways:

By Internet: You may vote by submitting a proxy over the Internet. Please refer to the **WHITE** proxy card or voting instruction form provided to you by your broker for instructions of how to vote by Internet.

By Telephone: Shareholders located in the United States that receive proxy materials by mail may vote by submitting a proxy by telephone by calling the toll-free telephone number on your proxy card or voting instruction form and following the instructions.

By Mail: If you received proxy materials by mail, you can vote by submitting a proxy by mail by marking, dating, signing and returning the **WHITE** proxy card in the postage-paid envelope.

In Person at the 2017 Annual Meeting: If you attend the 2017 Annual Meeting, you may deliver your completed **WHITE** proxy card in person or you may vote by completing a ballot, which we will provide to you at the 2017 Annual Meeting. You are encouraged to complete, sign and date the **WHITE** proxy card and mail it in the enclosed postage pre-paid envelope regardless of whether or not you plan to attend the 2017 Annual Meeting.

If you hold your shares of common stock in "street name," meaning such shares are held for your account by a broker, bank or other nominee, then you will receive instructions from such institution or person on how to vote your shares. Your broker, bank or other nominee will allow you to deliver your voting instructions via the Internet and may also permit you to submit your voting instructions by telephone.

Proxy Solicitation of the Dissident Group

The Dissident Group has notified the Company of its intention to nominate two candidates for election as a director at the 2017 Annual Meeting in opposition to the current directors who have been nominated by the board. You may receive proxy solicitation materials from the Dissident Group. The Company is not responsible for the accuracy of any information provided by or relating to the Dissident Group or its nominees contained in solicitation materials filed or disseminated by or on behalf of the Dissident Group or any other statements that the Dissident Group may make. **The board does NOT endorse the Dissident Group nominees and strongly recommends that you NOT sign or return any proxy card sent to you by the Dissident Group. If you have previously voted using a proxy card sent to you by the Dissident Group, you can subsequently revoke that vote by following the instructions on the WHITE proxy card to vote over the Internet or by telephone or by completing, signing and dating the enclosed WHITE proxy card and mailing it in the postage pre-paid envelope provided. Only your latest dated proxy will count. Any proxy may be revoked at any time prior to its exercise at the 2017 Annual Meeting as described in the accompanying Proxy Statement**.

Proxy Card

The shares represented by any proxy card which is properly executed and received by the Company prior to or at the 2017 Annual Meeting will be voted in accordance with the specifications made thereon. Where a choice has been specified on the **WHITE** proxy card with respect to the proposals, the shares represented by the **WHITE** proxy card will be voted in accordance with the specifications. If you return a validly executed **WHITE** proxy card without indicating how your shares should be voted on a matter and you do not revoke your proxy, your proxy will be voted: **FOR** the election of the three director nominees of the board set forth on the **WHITE** proxy card (Proposal 1); **FOR**, on an advisory basis, the approval of the non-binding resolution on the compensation of the Company's Named Executive Officers as described in the Proxy Statement under "Executive Compensation," (Proposal 2); **FOR** the approval of the Fiesta Restaurant Group, Inc. 2012 Stock Incentive Plan, as amended, for purposes of complying with Section 162(m) of the Internal Revenue Code of 1986, as amended, (Proposal 3); **FOR** the approval of an amendment to our Restated Certificate of Incorporation to implement a majority voting standard in uncontested elections of directors (Proposal 4); and **FOR** the ratification of the appointment of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for the 2017 fiscal year (Proposal 5).

The board is not aware of any matters that are expected to come before the 2017 Annual Meeting other than those described in this Proxy Statement. If any other matter should be presented at the 2017 Annual Meeting upon which a vote may be properly taken, shares represented by all **WHITE** proxy cards received by the board will be voted with respect thereto at the discretion of the persons named as proxies in the enclosed proxy card.

Record Date

Only holders of record of common stock at the close of business on [ ], 2017 will be entitled to notice of and to vote at the 2017 Annual Meeting.

Quorum

A majority of the outstanding shares of common stock, present in person or represented by proxy at the 2017 Annual Meeting, will constitute a quorum for the transaction of business. Votes withheld, abstentions and broker non-votes will be counted as present or represented for purposes of determining the presence or absence of a quorum for this meeting. In the absence of a quorum, the 2017 Annual Meeting may be adjourned by a majority of the votes entitled to be cast represented either in person or by proxy.

Required Vote

As a holder of our common stock, you are entitled to one vote per share on any matter submitted to a vote of the shareholders, subject to rights shareholders may have to cumulate votes for Proposal 1, as described below.

Our Restated Certificate of Incorporation and Bylaws require that directors are elected by a plurality of the votes cast. Proposal 1, regarding the election of three directors to our board, therefore will require approval of a plurality of the votes cast, meaning that the director nominees receiving the highest numbers of “for” votes of the shares entitled to be voted for them, up to the number of directors to be elected by such shares, will be elected. As a result, the three director nominees receiving the most “for” votes at the 2017 Annual Meeting will be elected.

The enclosed **WHITE** proxy card enables a shareholder to vote “FOR” or “WITHHOLD” from voting as to each director nominated by the board. If you vote “withhold” for any director nominee, as opposed to voting “FOR” any such director nominee, your shares voted as such will be counted for purposes of establishing a quorum, but will not be considered to have been voted FOR the director nominee and as such will have no effect the outcome of the vote on Proposal 1. Abstentions and broker non-votes will not constitute votes cast or votes withheld on Proposal 1 and will accordingly have no effect on the outcome of the vote on Proposal 1.

PLEASE SUPPORT THE BOARD’S NOMINEES BY VOTING “FOR” THE ELECTION OF THE BOARD’S NOMINEES UNDER PROPOSAL 1 USING THE ENCLOSED WHITE PROXY CARD. DO NOT COMPLETE OR RETURN A PROXY CARD FROM THE DISSIDENT GROUP, EVEN IF YOU VOTE “WITHHOLD” ON THEIR DIRECTOR NOMINEES. DOING SO MAY CANCEL ANY PREVIOUS VOTE YOU CAST ON THE COMPANY’S WHITE PROXY CARD

Approval of Proposals 2, 3, 5, and 6 requires the affirmative vote of a majority of the votes cast. The enclosed **WHITE** proxy card enables a shareholder to vote “FOR,” “AGAINST” or “ABSTAIN” on these proposals. Each of Proposals 2, 3, 5, and 6 will pass if the total votes cast “for” a given proposal exceed the total number of votes cast “against” such given proposal.

Approval of Proposal 4 requires the affirmative vote of 66 % of the outstanding shares of our common stock.

THE BOARD UNANIMOUSLY RECOMMENDS VOTING

FOR THE ELECTION OF EACH OF THE BOARD'S NOMINEES ON PROPOSAL 1 AND

FOR PROPOSALS 2, 3, 4 AND 5 USING THE ENCLOSED WHITE PROXY CARD.

THE BOARD URGES YOU NOT TO SIGN, RETURN OR VOTE ANY PROXY CARD SENT TO YOU

BY THE DISSIDENT GROUP.

Abstentions and Broker Non-Votes

If you are a beneficial owner holding your shares in "street name" and you do not provide voting instructions to your bank, broker, trustee or other nominee holding shares of our common stock for you, your shares of common stock will not be voted with respect to any proposal for which the shareholder of record does not have "discretionary" authority to vote. You are deemed to beneficially own your shares in "street name" if your shares are held in an account at a brokerage firm, bank, broker-dealer, trust or other similar organization. If this is the case, you will receive a separate voting instruction form with this Proxy Statement from such organization. As the beneficial owner, you have the right to direct your broker, bank, trustee, or nominee how to vote your shares. If you hold your shares in street name and do not provide voting instructions to your broker, bank, trustee or nominee, your shares will not be voted on any proposals on which such party does not have discretionary authority to vote (a "broker non-vote"). Broker "non-votes" are not counted in the tabulations of the votes cast or present at the meeting and entitled to vote on any of the proposals and therefore will have no effect on the outcome of the proposals.

Because the Dissident Group has initiated a proxy contest, to the extent that the Dissident Group provides a proxy card or voting instruction form to shareholders in street name, none of proposals in this Proxy Statement will be discretionary. We encourage you to provide voting instructions on a **WHITE** proxy card or a provided voting instruction form to the bank, broker, trustee or other nominee that holds your shares by carefully following the instructions provided in their notice to you.

Revocability of Proxy

A shareholder of record who has properly executed and delivered a proxy may revoke such proxy at any time before the 2017 Annual Meeting in any of the four following ways:

timely complete and return a new proxy card bearing a later date;

vote on a later date by using the Internet or telephone;

deliver a written notice to our Secretary prior to the 2017 Annual Meeting by any means, including facsimile, stating that your proxy is revoked; or

attend the 2017 Annual Meeting and vote in person.

If you have previously submitted a proxy card sent to you by the Dissident Group, you may change your vote by completing and returning the enclosed **WHITE** proxy card in the accompanying postage pre-paid envelope, or by voting by telephone or via the Internet by following the instructions on the **WHITE** proxy card. Submitting a proxy card sent to you by the Dissident Group will revoke votes you have previously made via the Company's **WHITE** proxy card.

If your shares are held of record by a bank, broker, trustee or other nominee other nominee and you desire to vote at the 2017 Annual Meeting, you may change your vote by submitting new voting instructions to your broker in accordance with such broker's procedures.

Appraisal Rights

Holders of shares of common stock do not have appraisal rights under Delaware law in connection with this proxy solicitation.

Shareholder List

A list of our shareholders as of the close of business on [ ], 2017 will be available for inspection during business hours for ten days prior to the 2017 Annual Meeting at our principal executive offices located at 14800 Landmark Boulevard, Suite 500, Dallas, TX 75254.

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Communications with the Board

Any shareholder or other interested party who desires to communicate with our Chairman of the board of directors or any of the other members of the board of directors may do so by writing to: Board of Directors, c/o Stacey Rauch, Chairman of the Board of Directors, Fiesta Restaurant Group, Inc., 14800 Landmark Boulevard, Suite 500, Dallas, Texas 75254 or by email at frgiboard@frgi.com. Communications may be addressed to the Chairman of the board, an individual director, a board committee, the non-management directors, or the full board. Communications will then be distributed to the appropriate directors unless the Chairman determines that the information submitted constitutes "spam," offensive or inappropriate material, and/or communications offering to buy or sell products or services.

Other Matters

If you have any questions or require any assistance with voting your shares, or if you need additional copies of the proxy materials, please contact:

105 Madison Avenue

New York, New York 10016

proxy@mackenziepartners.com

Call Collect: (212) 929-5500

or

Toll-Free: (800) 322-2885

Email: fiesta@mackenziepartners.com

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE 2017 ANNUAL MEETING TO BE HELD ON [ ], 2017: THE PROXY STATEMENT FOR THE 2017 ANNUAL MEETING AND THE ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR-ENDED JANUARY 1, 2017 ARE AVAILABLE FREE OF CHARGE ON OUR WEBSITE AT WWW.FRGI.COM.

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OTHER INFORMATION

Participants in the Solicitation

Under applicable regulations of the SEC, each of our directors and certain of our executive officers and other employees are "participants" in this proxy solicitation. Please refer to the sections entitled "Security Ownership of Certain Beneficial Owners and Management" and "Proposal 1—Election of Directors" for information about our directors and executive officers. Additional information relating to our directors and director nominees as well as certain of our officers and employees who are considered "participants" in our solicitation under the rules of the SEC by reason of their position as directors and director nominees of the Company or because they may be soliciting proxies on our behalf is attached to this Proxy Statement as Appendix A. Other than the persons described in this Proxy Statement, no general class of employee of the Company will be employed to solicit shareholders in connection with this proxy solicitation. However, in the course of their regular duties, employees may be asked to perform clerical or ministerial tasks in furtherance of this solicitation.

Costs of Solicitation

We are required by law to convene an annual meeting of shareholders at which directors are elected. Because our shares are widely held, it would be impractical for our shareholders to meet physically in sufficient numbers to hold a meeting. Accordingly, the Company is soliciting proxies from our shareholders. United States federal securities laws require us to send you this Proxy Statement, and any amendments and supplements thereto, and to specify the information required to be contained in it. The Company will bear the expenses of calling and holding the 2017 Annual Meeting and the solicitation of proxies therefor. These costs will include, among other items, the expense of preparing, assembling, printing and mailing the proxy materials to shareholders of record and beneficial owners, and reimbursements paid to brokerage firms, banks and other fiduciaries for their reasonable out-of pocket expenses for forwarding proxy materials to shareholders and obtaining beneficial owner's voting instructions. In addition to soliciting proxies by mail, directors, officers and employees may solicit proxies on behalf of the board, without additional compensation, personally or by telephone. We may also solicit proxies by email from shareholders who are our employees or who previously requested to receive proxy materials electronically. As a result of the potential proxy solicitation by the Dissident Group, we may incur additional costs in connection with our solicitation of proxies. The Company has retained MacKenzie Partners, Inc. to solicit proxies. Under our agreement with MacKenzie Partners, Inc., MacKenzie Partners, Inc. will receive a fee of up to $[ ] plus the reimbursement of reasonable expenses. MacKenzie Partners, Inc. expects that approximately [ ] of its employees will assist in the solicitation. MacKenzie Partners, Inc. will solicit proxies by mail, telephone, facsimile or email. Our aggregate expenses, including those of MacKenzie Partners, Inc., related to our solicitation of proxies, excluding salaries and wages of our regular employees, are expected to be approximately $[ ], of which approximately $[ ] has been incurred as of the date of this Proxy Statement.

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FORWARD-LOOKING STATEMENTS

This Proxy Statement contains forward-looking statements within the meaning of the Section 27A of the Securities Act of 1933, as amended (the "*Securities Act*"), Section 21E of the Securities Exchange Act of 1934 (the "*Exchange Act*") and the Private Securities Litigation Reform Act of 1995. All statements relating to events or results that may occur in the future, including, but not limited to, the Company's future costs of solicitation, record or meeting dates, compensation arrangements, plans or amendments (including those related to profit sharing and stock-based compensation), company policies, corporate governance practices, documents or amendments (including charter or bylaw amendments, shareholder rights plans or similar arrangements) as well as capital and corporate structure (including major shareholders, board structure and board composition), are forward-looking statements. Forward-looking statements generally can be identified by words such as "expect," "will," "change," "intend," "target," "future "potential," "estimate," "anticipate," "to be," and similar expressions. These statements are based on numerous assumptions and involve known and unknown risks, uncertainties and other factors that could significantly affect the Company's operations and may cause the Company's actual actions, results, financial condition, performance or achievements to be substantially different from any future actions, results, financial condition, performance or achievements expressed or implied by any such forward-looking statements. Those factors include, but are not limited to, (i) increases in food and other commodity costs, (ii) risks associated with the expansion of our business, including increasing construction costs, (iii) risks associated with food borne illness or other food safety issues, including negative publicity through traditional and social media, (iv) our ability to manage our growth and successfully implement our business strategy, (v) labor and employment benefit costs, including the impact of increases in federal and state minimum wages, increases in exempt status salary levels and healthcare costs imposed by the Affordable Care Act, (vi) cyber security breaches, (vii) general economic conditions, particularly in the retail sector, (viii) competitive conditions, (ix) weather conditions, (x) significant disruptions in service or supply by any of our suppliers or distributors, (xi) increases in employee injury and general liability claims, (xii) changes in consumer perception of dietary health and food safety, (xiii) regulatory factors, (xiv) fuel prices, (xv) the outcome of pending or future legal claims or proceedings, (xvi) environmental conditions and regulations, (xvii) our borrowing costs; (xviii) the availability and terms of necessary or desirable financing or refinancing and other related risks and uncertainties, (xix) the risk of an act of terrorism or escalation of any insurrection or armed conflict involving the United States or any other national or international calamity, (xx) factors that affect the restaurant industry generally, including product recalls, liability if our products cause injury, ingredient disclosure and labeling laws and regulations and (xxi) other risks, uncertainties and factors indicated from time to time in the Company's reports and filings with the SEC including, without limitation, most recently the Company's Annual Report on Form 10-K for the year ended January 1, 2017, under the heading Item 1A - "Risk Factors" and the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations." The Company does not intend, and undertakes no obligation to update or publicly release any revision to any such forward-looking statements, whether as a result of the receipt of new information, the occurrence of subsequent events, the change of circumstance or otherwise. Each forward-looking statement contained in this Proxy Statement is specifically qualified in its entirety by the aforementioned factors. You are hereby advised to carefully read this Proxy Statement in conjunction with the important disclaimers set forth above prior to reaching any conclusions or making any investment decisions.

BACKGROUND TO THE SOLICITATION

On February 24, 2016, the Company announced its intent to pursue a tax-efficient spin-off of Taco Cabana, subject to board and regulatory approval, to be effected in late 2017 or in 2018. The Company further indicated that a more detailed separation plan, including the transaction structure, timing, composition of senior management, and capital structure, would be disclosed as the Company's plans evolved.

Poor restaurant industry market conditions that developed in late 2015 further worsened throughout the first half of 2016, dramatically accelerating a downturn in our business. As the board evaluated what impact the deteriorating market dynamics would have on the potential spin-off and the emerging market development plan, it also began discussions with our then Chief Executive Officer and President on his potential retirement. These discussions, along with shareholder engagement and further evaluation of the Company's operating performance, continued over the next several months.

On August 9, 2016, at the request of James Pappas and as part of our ongoing shareholder engagement efforts, members of the Company's management team spoke to Mr. Pappas and other members of the yet-to-be-formed Dissident Group by telephone and discussed a range of topics relating to the Company's business.

On August 25, 2016, the Company issued a press release announcing that then Chief Executive Officer and President Timothy Taft would retire at the end of 2016, and that the board had appointed a Special Committee to search for a new Chief Executive Officer and President and to consider the composition of the board. The committee consisted of Stacey Rauch (who served as chair), Stephen Elker and Barry Alperin. The Company also announced its intent to formally review the Company's strategic plan, including the previously announced spin-off of Taco Cabana and the Company's emerging market development plan, in light of new market dynamics and recent operating performance.

On August 26, 2016, Mr. Pappas informed the Company that the Dissident Group was approaching 5% ownership of the Company's outstanding common stock and requested another meeting with management of the Company.

On September 7, 2016, members of the Company's management team met with Mr. Pappas, who indicated that the Dissident Group intended to continue accumulating shares of the Company's common stock.

On September 19, 2016, the Dissident Group filed a Schedule 13D with the SEC, disclosing aggregate beneficial ownership of approximately 6.2% of the outstanding shares of the Company's common stock and indicating its intent

to engage in discussions with the board and management regarding the Company’s capital allocation, corporate governance, operations and other strategic plans.

On September 22, 2016, director Nicholas Daraviras and Mr. Pappas spoke by telephone to discuss scheduling a call with Mr. Pappas and additional members of the board.

On September 27, 2016, the Company issued a press release providing an update on the board composition, management transition and strategic plan review previously announced in August. The press release announced (i) the appointment of Danny Meisenheimer, then Chief Operating Officer of Pollo Tropical, as interim Chief Executive Officer and President, (ii) the commencement of a search for a seasoned restaurant executive to fill the Chief Executive Officer and President position permanently and for additional non-executive director candidates with extensive restaurant industry experience and (iii) the retention of Heidrick & Struggles – a leading global executive search firm – to assist with both the executive and director searches. Additionally, the Company announced that it would not proceed with the spin-off of Taco Cabana and would suspend the development of additional Pollo Tropical Restaurants in Texas.

On September 29, 2016, Mr. Daraviras and other members of the board, and Mr. Pappas and Mr. Radley L. Radoff, spoke by telephone regarding a potential settlement proposal.

On September 30, 2016, the Dissident Group delivered a term sheet outlining a settlement proposal (the “Dissident Settlement Proposal”) between the Dissident Group and the Company. The terms of the Dissident Settlement Proposal included, among other terms, (i) the immediate appointment of James C. Pappas and an additional director candidate to-be-identified by the Dissident Group to the board, (ii) the inclusion of a proposal to declassify the board in the agenda for the 2017 Annual Meeting, (iii) the creation of a Special Committee of the board to review strategic alternatives, with Mr. Pappas as member, (iv) the addition of Mr. Pappas to the CEO search committee of the Company, (v) a limited standstill covering the 2017 Annual Meeting and (iv) expense reimbursement for the Dissident Group.

On October 7, 2016, Mr. Pappas contacted Mr. Daraviras by email inquiring about the status of the Company’s response to the Dissident Settlement Proposal and setting a deadline of October 14, 2016 for the Dissident Group to receive a response by the Company before moving forward with a proxy contest.

On October 14, 2016, the board delivered a letter to JCP Investment Partnership, LP ("JCP Partnership") indicating that the board had reviewed the Dissident Settlement Proposal and determined that entering into settlement negotiations was inappropriate at that time, but that the board and management remained open to constructive dialogue with the Dissident Group. In the letter, the board also invited the Dissident Group to submit names and resumes of director candidates that are qualified for the Corporate Governance and Nominating Committee (the "CG&N Committee") to consider for appointment to the board as part of the Company's ongoing review of board composition previously announced in August. The correspondence between the Company and the Dissident Group was disclosed by the Dissident Group in an amended Schedule 13D filed by the Dissident Group on October 18, 2016.

On October 17, 2016, the board appointed a Special Committee to evaluate potential strategic alternatives available to the Company, including a possible sale of the Company. The Special Committee consisted of Mr. Elker (who served as Chair), Ms. Rauch and Jack A. Smith and it retained separate financial and legal advisors to assist it in this evaluation.

On October 24, 2016, the Company announced that, in connection with a thorough strategic review of the Company's ongoing operations, previously announced in August, and the economic environment impacting the restaurant industry, the Company was closing 10 Pollo Tropical restaurants, up to three of which would be rebranded as Taco Cabana restaurants in certain Texas locations.

On December 12, 2016, and December 13, 2016, Mr. Daraviras and Mr. Pappas corresponded by email to discuss scheduling a call with Mr. Pappas and additional members of the board.

On December 20, 2016, members of the board spoke with Joshua E. Schechter and Mr. Pappas by telephone regarding the Dissident Group's demands. During this call, Mr. Schechter spoke at length in support of the appointment of Mr. Pappas to the board. No other potential nominees of the Dissident Group were discussed or put forward.

Throughout December 2016 and January 2017 the board continued to pursue the initiatives previously announced in August to (i) consider strategic options for the company, (ii) hire an experienced Chief Executive Officer and President, and (iii) identify and appoint an additional industry leader to the board.

On January 26, 2017, JCP Partnership delivered a letter (the "Nomination Notice") to Joseph A. Zirkman, Senior Vice President, General Counsel and Secretary of the Company. The letter was a formal notice of intent to nominate John B. Morlock, James C. Pappas and Joshua E. Schechter as candidates for election to the board as Class II directors at the 2017 Annual Meeting. The Nomination Notice disclosed that the Dissident Group beneficially owned approximately 7.1% of the outstanding shares of the Company's common stock. The Dissident Group disclosed the

nominations in a press release on January 30, 2017 and filed an amended Schedule 13D on the same day, disclosing both the nominations and its increased ownership of the Company's common stock.

On January 30, 2017, the Company issued a press release stating that it would review the Nomination Notice and present its recommendations to the Company's shareholders in its proxy statement for the 2017 Annual Meeting.

On February 14, 2017, Mr. Pappas, on behalf of JCP Partnership, delivered a letter (the "JCP Demand Letter") to the Company demanding an inspection pursuant to applicable Delaware law of the Company's shareholder lists and certain other books and records.

On February 21, 2017, the Company's outside legal counsel, Vinson & Elkins, L.L.P., delivered a letter to JCP Partnership in response to the JCP Demand Letter. The letter stated that the Company was prepared to make available information to which a shareholder is entitled under applicable Delaware law, subject to customary conditions which JCP Partnership subsequently fulfilled.

On February 22, 2017, upon the recommendation of the Special Committee formed in August 2016 and tasked with conducting a review of the board's composition and of the Corporate Governance and Nomination Committee, the board met and voted unanimously to appoint Paul E. Twohig, a restaurant industry veteran, as a Class I member of the board effective February 28, 2017.

Between February 24, 2017 and March 3, 2017, members of management and the board engaged in several conversations with members of the Dissident Group regarding a potential settlement of the proxy contest.

On February 27, 2017, the Company issued a press release providing an update on the board composition, management transition and strategic plan review previously announced in August. The press release announced the appointment of (i) Richard C. Stockinger, an accomplished industry executive, as Chief Executive Officer and President of the Company; (ii) Danny Meisenheimer, the former Interim Chief Executive Officer and President of the Company, as Senior Vice President, Chief Operating Officer of the Company; (iii) Paul E. Twohig as a Class I member of the board; and (iv) Stacey Rauch, a current member of the board, as Chairman of the board of directors, in each case effective as of February 28, 2017. The board also provided a strategic update which included the suspension of the review of strategic alternatives, in which no potential counterparty presented a final proposal to acquire the Company, and the Company's intent to pursue a refocused growth strategy going forward.

On February 28, 2017, the Dissident Group filed an amended Schedule 13D with the SEC, disclosing aggregate beneficial ownership of approximately 8.5% of the outstanding shares of the Company’s common stock.

On March 5, 2017, the board met to discuss potential settlement of the proxy contest with the Dissident Group.

On March 6, 2017, Mr. Zirkman and Mr. Daraviras spoke to Mr. Pappas by telephone to indicate that the board was prepared to interview Mr. Pappas and Mr. Morlock as potential nominees to the board in order to thoroughly evaluate their qualifications. Mr. Zirkman and Mr. Daraviras further expressed that, at that time, the board could not commit to adding any specific number of directors or to removing any existing directors from the board in connection with a settlement of the proxy contest.

On March 12, 2017 and March 15, 2017, members of the board (along with certain members of management) met with Mr. Morlock and Mr. Pappas to interview them as candidates for the board.

On March 19, 2017, the board met by telephone to discuss the status of negotiations with the Dissident Group and initial interviews with Mr. Morlock and Mr. Pappas. The board agreed to consider appointing Mr. Pappas to the board as part of a settlement proposal to the Dissident Group.

On March 20, 2017, Jamba, Inc. (“Jamba”) filed a Form 12b-25 with the SEC disclosing that it would be delayed in filing its Annual Report on Form 10-K for 2016 because Jamba had not yet completed its financial statements, which prevented Jamba’s accounting firm from completing its audit of the Company’s financial statements and assessment of the Company’s internal control over financial reporting. Mr. Pappas is a director of Jamba and a member of Jamba’s audit committee. On March 24, 2017, Jamba filed a Form 8-K announcing that it had received a letter from the Nasdaq Stock Market LLC (“NASDAQ”) indicating that Jamba is not in compliance with NASDAQ’s requirements for continued listing because the Company had delayed in filing its Form 10-K.

From March 20, 2017 to March 27, 2017, Mr. Daraviras engaged in conversations by telephone with Mr. Pappas regarding a potential settlement of the proxy contest by an agreement to appoint Mr. Pappas to the board. In the conversations with Mr. Pappas, Mr. Daraviras advised Mr. Pappas that the board was willing to appoint Mr. Pappas to the board and to the CG&N Committee and would agree to make a public statement that the board was willing to consider adding an additional industry expert to the board at a later date.

On March 27, 2017, Mr. Daraviras and Mr. Pappas had an additional discussion regarding the appointment of an additional independent director, and the Dissident Group's new request that the Board remove an existing director. Mr. Pappas asked if Mr. Daraviras would speak to Mr. Schechter in order to convey the Company's position. Later that date, Mr. Daraviras spoke to Mr. Schechter by telephone on the same subject. At the end of the discussion, Mr. Daraviras asked for the appropriate contact person for the Dissident Group regarding the potential settlement, and Mr. Schechter advised that the board should contact Mr. Pappas. Following that discussion, Mr. Daraviras called Mr. Pappas and left a voice mail message which was never returned. Neither Mr. Pappas nor Mr. Schechter has followed up with Mr. Daraviras to continue conversations since March 27.

On April 6, 2017 and April 10, 2017, nearly two weeks after the board's last effort to continue settlement discussions with Mr. Pappas, Thomas Purcell, another member of the Dissident Group, contacted Mr. Daraviras to engage in another round of settlement discussions. Mr. Purcell and Mr. Daraviras spoke a number of times by telephone over the course of two days to discuss a potential settlement of the proxy contest. Mr. Daraviras advised Mr. Purcell that as the Company had recently added Paul E. Twohig, an industry expert, to the board, the board did not consider it prudent to commit to adding Mr. Pappas plus an additional candidate to the board at that time. Mr. Purcell advised Mr. Daraviras that the Dissident Group remained committed to requiring the appointment of an additional industry expert to the board, possibly in conjunction with the removal of one of the Company's current directors, and that the appointment of the proposed new industry expert to the board would require their approval. Mr. Daraviras also requested additional information on how the delayed filing disclosed by Jamba would impact Mr. Pappas's fitness as a nominee for the Company's board. As of the date of the publication of the document, Mr. Pappas has not provided the Company with sufficient assurances that these circumstances are not pertinent to the Company's considerations of Mr. Pappas's candidacy as a director of the Company.

On April 11, 2017, Mr. Purcell and Mr. Daraviras continued their discussion regarding potential settlement. Mr. Daraviras advised Mr. Purcell that the Company was prepared to agree to add (i) Mr. Pappas to the board, and appoint him to serve on the CG&N Committee (ii) an additional board member with restaurant experience within the next 12 months. In return, the Dissidents Group would agree to a two-year standstill with respect to any proxy contest in connection with election of the Company's directors. Mr. Daraviras indicated the Company would consider payment of a portion of the Dissident Group's legal fees and further requested an accounting of any such reimbursement request. Mr. Daraviras also requested an update on the status of a response from Mr. Pappas on the questions related to the Jamba disclosures. Mr. Purcell responded later that day that the remainder of the Dissident Group would require that the proposed new independent director must be approved unanimously by the CG&N Committee or by a majority of the CG&N Committee (provided Mr. Pappas was in the majority), rather than by a simple majority of the CG&N Committee on which the Company offered Mr. Pappas membership, and that they were unwilling to enter into a two-year standstill.

On April 12, 2017, the Dissident Group delivered an open letter to the Chairman of the Company's board of directors, rejecting the Company's proposal that was discussed on April 11, 2017 and indicating its intent to withdraw the nomination of Mr. Schechter.

On April 13, 2017, the Company filed the preliminary version of this Proxy Statement with the SEC.

PROPOSAL 1—ELECTION OF DIRECTORS

Our board of directors is divided into three classes of directors, with the classes as nearly equal in number as possible, each serving staggered three-year terms as described below.

The terms of office of our Class I, Class II, and Class III directors are:

Class I directors, whose term will expire at the 2019 Annual Meeting of Shareholders and when their successors are duly elected and qualified;

Class II directors, whose term will expire at this 2017 Annual Meeting and when their successors are duly elected and qualified; and

Class III directors whose term will expire at the 2018 Annual Meeting of Shareholders and when their successors are duly elected and qualified.

Our Class I directors are Stacey Rauch and Paul E. Twohig; our Class II directors are Brian P. Friedman, Stephen P. Elker and Barry J. Alperin; and our Class III directors are Nicholas Daraviras and Jack A. Smith.

Three directors will be elected at the 2017 Annual Meeting as Class II directors of the Company for a term of three years expiring at the Annual Meeting of Shareholders to be held in 2020 and until their successors shall have been elected and qualified. The election of directors requires the affirmative vote of a plurality of the shares of common stock present in person or by proxy at the 2017 Annual Meeting. **Each proxy received will be voted FOR the election of the three directors named below unless otherwise specified in the proxy.** At this time, our board of directors knows of no reason why the Company’s three nominees would be unable to serve. There are no arrangements or understandings between any nominee and any other person pursuant to which such person was selected as a nominee.

Our Corporate Governance and Nominating Committee has reviewed the qualifications of the three Class II director nominees and has recommended the election of the three directors recommended by the board.

Director Nominees’ Principal Occupations, Business Experience, Qualifications and Directorships

Name of Nominee	Committee Membership	Principal Occupation	Age	Director Since
Barry J. Alperin	Audit, Corporate Governance and Nominating, Finance (Chair)	Director of Fiesta Restaurant Group	76	2012
Stephen P. Elker	Audit (Chair), Corporate Governance and Nominating	Director of Fiesta Restaurant Group	65	2012
Brian P. Friedman	Compensation, Corporate Governance and Nominating	President and a director of Leucadia National Corporation; Director of Fiesta Restaurant Group	61	2011

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Barry J. Alperin

Director since 2012
Age: 76

Having served as both an executive within the retail industry and an attorney, Mr. Alperin possesses deep financial, operational, legal and management skills. Additionally, his service on the boards of several public companies allows him to bring significant corporate governance and leadership experience to our board of directors.

Biography:

<u>Committee Membership:</u>

Audit

Corporate Governance and Nominating

Finance (Chair)

Barry J. Alperin has served as a director of Fiesta Restaurant Group since July 2012. Mr. Alperin, who is retired, served as Vice Chairman of Hasbro, Inc. (“Hasbro”) from 1990 through 1995, as Co-Chief Operating Officer of Hasbro from 1989 through 1990 and as Senior Vice President or Executive Vice President of Hasbro from 1985 through 1989. He was a director of Hasbro from 1985 through 1996. Prior to joining Hasbro, Mr. Alperin practiced law in New York City for 20 years, dealing with corporate, public and private financial transactions, corporate mergers and acquisitions, compensation issues and securities law matters. Mr. Alperin currently serves as a director of Henry Schein, Inc. (and is Chairman of its Compensation Committee and a member of its Audit Committee and its Nominating and Governance Committee) and is a director of a privately held marine construction corporation, Weeks Marine, Inc. Since November 2013, Mr. Alperin has served as a director of Jefferies Group LLC (a wholly-owned subsidiary of Leucadia National Corporation, where Mr. Friedman is an executive officer and director) and serves on its Audit, Compensation, and Governance Committees. During the past five years, Mr. Alperin served on the board of directors of The Hain Celestial Group, Inc. (and was Chairman of its Corporate Governance and Nominating Committee and a member of its Audit Committee). He serves as a trustee and member of the Executive Committee of The Caramoor Center for Music and the Arts, President Emeritus and a Life Trustee of The Jewish Museum in New York City and is a past President of the New York Chapter of the American Jewish Committee where he also served as Chairman of the Audit Committee of the national organization. Mr. Alperin also formerly served as Chairman of the Board of Advisors of the Tucker Foundation at Dartmouth College, was President of the Board of the Stanley Isaacs Neighborhood Center in New York City, was a trustee of the Hasbro Children’s Foundation, was President of the Toy Industry Association and was a member of the Columbia University Medical School Health Sciences Advisory Council.

Stephen P. Elker

Director since 2012
Age: 65

Mr. Elker, with over 36 years of experience with KPMG LLP, brings to our board of directors extensive knowledge of accounting and tax practices that strengthens our board of directors’ collective knowledge, capabilities and experience.

Committee Membership:	**Biography:**
Audit (Chair) Corporate Governance and Nominating	Stephen P. Elker has served as a director of Fiesta Restaurant Group since May 7, 2012. Until 2009, Mr. Elker spent over 36 years with KPMG LLP, the U.S. member firm of KPMG International, beginning in its Washington D.C. office, and then with offices in Rochester, New York and Orlando, Florida. In 1999, Mr. Elker was appointed as managing partner of the Orlando office and served as partner in charge of the Florida business tax practice from 2001 to 2009. Mr. Elker also served as a member of the Nominating Committee and Strategy Committee of KPMG. During his career with KPMG, Mr. Elker led engagements for several hospitality and retail clients including large, multi-unit restaurant companies. Mr. Elker is a certified public accountant and currently serves as an independent director and Chairman of the Audit Committee of CNL Growth Properties, Inc., a public, non-traded real estate investment trust. Mr. Elker also serves on the board of directors of other privately held companies in the finance and payments industries.

Brian P. Friedman **Director since 2011** **Age: 61** **Committee Membership:**	**Having an extensive career in the legal, investment banking, investments and management fields, Mr. Friedman brings to our board of directors significant experience related to the business and financial issues facing public corporations. In addition, through Mr. Friedman's service on the boards of a number of his firm's portfolio companies over time, he combines significant executive experience with his knowledge of the strategic, financial and operational issues of restaurant companies.** **Biography:**
Compensation Corporate Governance and Nominating	Brian P. Friedman has served as a director of Fiesta Restaurant Group since April 2011. Mr. Friedman has been the President and a director of Leucadia National Corporation ("Leucadia") since March 1, 2013, a director and executive officer of Jefferies Group LLC since July 2005, Chairman of the Executive Committee of Jefferies LLC since 2002, and President of Jefferies Capital Partners LLC ("Jefferies Capital Partners") and its predecessors since 1997. Mr. Friedman was previously employed by Furman Selz LLC and its successors, including serving as Head of Investment Banking and a member of its Management and Operating Committees. Prior to his 17 years with Furman Selz and its successors, Mr. Friedman was an attorney with the law firm of Wachtell Lipton Rosen & Katz. Mr. Friedman serves on boards of directors/managers of Leucadia's and Jefferies Capital Partners' private subsidiaries and investee companies. Mr. Friedman also serves or has served on the board of the following public companies: HomeFed Corporation (majority-owned by Leucadia) from April 2014 to present; and Carrols Restaurant Group, Inc. from July, 2009 to May, 2012.

Your board unanimously recommends a vote FOR the election of our three named Class II nominees to your board of directors, Brian P. Friedman, Stephen P. Elker, and Barry J. Alperin. Proxies received in response to this solicitation will be voted FOR the election of the three named Class II nominees to our board of directors unless otherwise specified in the proxy.

Principal Occupation, Business Experience, Qualifications and Directorships of Other Members of the Board of Directors

The following table sets forth information with respect to each of the other members of the board of directors whose term extends beyond the 2017 Annual Meeting, including the Class of such director and the year in which each such director's term will expire.

Name of Director	Committee Membership	Age	Director Since	Year Term Expires
Stacey Rauch	Compensation (Chair), Corporate Governance and Nominating	59	2012	2019 Class I
Paul E. Twohig	Compensation, Corporate Governance and Nominating	63	2017	2019 Class I
Nicholas Daraviras	Corporate Governance and Nominating, Finance	43	2011	2018 Class II
Jack A. Smith	Audit, Compensation, Corporate Governance and Nominating (Chair)	81	2011	2018 Class II

Stacey Rauch (Chair)

Director since 2012
Age: 59

With her public company board experience and distinguished career working with retailers, wholesalers and manufacturers during her 24 years at McKinsey & Company, Inc., Ms. Rauch brings to our board substantial expertise in business strategy, marketing, merchandising and operations in the retail industry.

<u>Committee Membership:</u>

Compensation (Chair)

Corporate Governance and Nominating

Biography:

Stacey Rauch has served as the non-executive Chairman of the board of directors of Fiesta Restaurant Group since February 2017 and as a director of Fiesta Restaurant Group since 2012.

Ms. Rauch is a Director Emeritus of McKinsey & Company, Inc. from which she retired in September 2010. Ms. Rauch was a leader in McKinsey's Retail and Consumer Goods Practices, served as the head of the North American Retail and Apparel Practice, and acted as the Global Retail Practice Convener. A 24 year veteran of McKinsey, Ms. Rauch led engagements for a wide range of retailers, apparel wholesalers, and consumer goods manufacturers. Her areas of expertise include strategy, organization, marketing, merchandising, multi-channel management, global expansion, and retail store operations. Ms. Rauch was a co-founder of McKinsey's New Jersey office, and was the first woman at McKinsey appointed as an industry practice leader. Ms. Rauch is also a non-Executive director of Land Securities, PLC, the UK's largest commercial property company, where she sits on its Audit Committee. Previously, Ms. Rauch served on the board of directors of CEB, Inc, a leading member-based advisory company, Ann, Inc., a women's specialty apparel retailer and, Tops Holding Corporation, the parent company of Tops Markets LLC, a US grocery retailer. Prior to joining McKinsey, Ms. Rauch spent five years in product management for the General Foods Corporation.

Paul E. Twohig

Director since 2017
Age: 63

With over 30 years of experience in the restaurant industry, Mr. Twohig brings to our board of directors significant leadership, management, operational, financial, marketing and franchising experience.

Committee Membership:

Compensation

Corporate Governance and Nominating

Biography:

Paul E. Twohig has served as a director of Fiesta Restaurant Group since February 2017. Mr. Twohig is a global retail and food service senior executive with demonstrated success leading some of the world's most prominent brands. From 2009 until 2017, Mr. Twohig served as President of Dunkin Donuts, U.S. and Canada. He was a member of the senior executive team that completed Dunkin Donuts' initial public offering in 2011. Previously, Mr. Twohig held several senior executive roles with Starbucks Corporation, including Vice President and General Manager, U.K., and Senior Vice President, Eastern Division. Additionally, Mr. Twohig served as Chief Operating Officer and Executive Vice President at Panera Bread Company. His governance experience includes serving as a member of the Board of Directors for Dentistry for Children from 2011 to 2014, and for Solantic Urgent Care, Inc. from 2007 to 2011.

Nicholas Daraviras

Director since 2011
Age: 43

Mr. Daraviras brings significant experience with the strategic, financial and operational issues of retail companies in connection with his service on the boards of a number of his firm's portfolio companies over time.

Committee Membership:

Corporate Governance and Nominating

Finance

Biography:

Nicholas Daraviras has served as a director of Fiesta Restaurant Group since April 2011. Mr. Daraviras has been a Managing Director of Leucadia since 2014. Mr. Daraviras has served as Vice President, Acquisitions of Landcadia Holdings, Inc. since May 2016. From 1996 through 2014, Mr. Daraviras was employed with Jefferies Capital Partners or its predecessors (of which Mr. Friedman is President and a director). He also served on the boards of Edgen Group Inc., a global distributor of specialty steel products, or its predecessors from February 2005 until 2013, and Carrols

Restaurant Group from 2009 until 2013. Mr. Daraviras served on the Compensation Committee of Carrols Restaurant Group, Inc. as well as the Compensation, Corporate Governance, and Nominating Committees of Edgen Group Inc. He also serves on several boards of directors of private portfolio companies of Jefferies Capital Partners and Leucadia.

Jack A. Smith

Director since 2011
Age: 81

Mr. Smith, as a former senior executive of several major retail organizations, together with service on the boards of public companies, including Carrols Restaurant Group and Darden Restaurants, Inc., brings significant leadership, management, operational, financial and brand management experience to our board of directors.

Committee Membership:

Audit

Compensation

Corporate Governance and Nominating (Chair)

Biography:

Jack A. Smith has served as a director of Fiesta Restaurant Group since 2011, and served as the non-executive Chairman of the board of directors of Fiesta Restaurant Group from February 2012 to February 2017. Mr. Smith also served as a director of Carrols Restaurant Group, Inc. and as Chairman of its Audit Committee from 2006 until 2012. Mr. Smith is President of SMAT, Incorporated, a consulting company specializing in consumer services. Mr. Smith founded The Sports Authority, Inc., a national sporting goods chain, in 1987 where he served as Chief Executive Officer until September 1998 and as Chairman until 1999. From 1982 until 1987, Mr. Smith served as Chief Operating Officer of Herman's Sporting Goods. Prior to Herman's, Mr. Smith served in executive management positions with other major retailers including Sears & Roebuck, Montgomery Ward, Jefferson Stores and Diana Shops. Mr. Smith currently serves as a non-executive director of Omagine, Inc., a hospitality and tourism company with significant property management and real estate development operations. Mr. Smith previously served on the board of directors of Darden Restaurants, Inc. and was the Chairman of its Audit Committee from 1995 through 2009.

Leadership Update

In February 2017, the Board provided a leadership update which included a number of changes designed to strengthen the Company and enhance our ability to create value for shareholders. These changes included the appointment of a new Chief Executive Officer ("CEO") as well as a new independent director, both of whom bring substantial industry expertise and strong track records of creating value at restaurant companies. These appointments were made as a result of extensive process to identify the strongest candidates to lead our company forward. On August 25, 2016, the board chose to form a Special Committee to lead the search process. Stacey Rauch served as the Chair of the Special Committee, with Steve Elker and Barry Alperin serving as members. Additionally, the Special Committee engaged a prominent executive search firm to identify CEO and director candidates. As a result of this process:

The board appointed Richard Stockinger as CEO. Mr. Stockinger has a strong track record as a director and executive with multiple private and public restaurant companies. The board is confident that he has the skills necessary to be an effective leader at this critical juncture.

Danny Meisenheimer, who acted as interim CEO from September 2016 – February 2017, assumed the role of Senior Vice President, Chief Operating Officer.

The Board appointed Paul Twohig as an independent director. Mr. Twohig brings a fresh perspective and extensive operating experience with highly successful and growing restaurant brands. His appointment was the result of an extensive process which included evaluating the skills of our current directors, and we believe Mr. Twohig is an ideal complement to our current directors.

The Board appointed Stacey Rauch as non-executive Chairman of the Board. This expanded leadership role was a natural progression for Ms. Rauch as she has been a director at Fiesta since 2012 and has extensive experience in the consumer and retail industries in her role as a 24 year veteran of McKinsey & Company, Inc.

Board Skills Assessment

The Board Skills assessment below illustrates the key skills that our board has identified as particularly valuable to the effective oversight of the Company and our strategy. This highlights the depth and breadth of skills possessed by current directors.

Information Regarding Executive Officers

Name of Officer	Age	Position
Richard Stockinger	58	Chief Executive Officer and President
Lynn S. Schweinfurth	49	Senior Vice President, Chief Financial Officer and Treasurer
Danny K. Meisenheimer	57	Senior Vice President, Chief Operating Officer
Joseph A. Zirkman	56	Senior Vice President, General Counsel and Secretary
Joseph W. Brink	50	Vice President, Chief Procurement Officer

Richard "Rich" Stockinger

Age: 58

Chief Executive Officer and President

Biography:

Richard "Rich" Stockinger has been Chief Executive Officer and President of Fiesta Restaurant Group since February 2017. Previously, he served as President and Chief Executive Officer of Benihana, Inc. ("Benihana") from 2009 until 2014, as a member of the Board of Directors of Benihana from 2008 until 2014, as a member of the Audit Committee of Benihana from 2008 until 2009, and as Chairman of the Board of Directors of Benihana from 2010 until 2012. Prior to joining Benihana, Mr. Stockinger spent more than two decades at The Patina Restaurant Group, LLC and its predecessor Restaurant Associates, Inc. during which time he served in various senior executive capacities, including as President from 2003 until 2008 and as a director from 1998 until 2006. Most recently, Mr. Stockinger had served as a consultant to Bruckmann, Rosser, Sherrill & Co., a private equity firm, from 2014 until 2017, and Not Your Average Joes, a private restaurant company of which Mr. Stockinger is also a member of its board of directors.

Lynn S. Schweinfurth

Age: 49

Senior Vice President, Chief Financial Officer and Treasurer

Biography:

Lynn S. Schweinfurth has been Vice President, Chief Financial Officer and Treasurer of Fiesta Restaurant Group since 2012 and was appointed Senior Vice President in February 2015. From 2010 to 2012, Ms. Schweinfurth served as Vice President of Finance and Treasurer of Winn-Dixie Stores, Inc. Ms. Schweinfurth was Chief Financial Officer of Lone Star Steakhouse and Texas Land & Cattle from 2009 to 2010. She was Vice President, Finance, at Brinker International, Inc. from 2004 to 2009.

Danny K. Meisenheimer

Age: 57

Senior Vice President, Chief Operating Officer

Biography:

Danny K. Meisenheimer has served as Fiesta Restaurant Group's Senior Vice President and Chief Operating Officer since February 2017 and formerly served as the Interim Chief Executive Officer and President from September 2016 until February 2017. Mr. Meisenheimer has also served as Pollo Tropical's Vice President and Chief Operating Officer from February 2013 until September 2016, the Interim Chief Operating Officer from September 2012 until February 2013 and as Chief Brand Officer from April 2012 until September 2012. Mr. Meisenheimer was Chief Operating Officer at Souper Salad, Inc. from 2010 until 2012 and Chief Brand Officer at Souper Salad, Inc. from 2008 until 2010. Mr. Meisenheimer was Vice President, Brand Management at Pizza Inn, Inc. from 2005 until 2008.

Joseph A. Zirkman

Biography:

Age: 56

Senior Vice President, General Counsel and Secretary	Joseph A. Zirkman has been Vice President, General Counsel and Secretary of Fiesta Restaurant Group since 2011 and was appointed Senior Vice President in February 2015. Mr. Zirkman was Vice President, General Counsel and Secretary of Carrols Restaurant Group, Inc. from 1993 until 2012. Mr. Zirkman was an associate with the New York City law firm of Baer Marks & Upham from 1986 until 1993.

Joseph W. Brink	**Biography:**
Age: 50	
Vice President, Chief Procurement Officer	Joseph W. Brink has been Vice President, Supply Chain Management of Fiesta Restaurant Group since 2011 and was appointed Chief Procurement Officer in October 2016. From 2008 to 2011, Mr. Brink served as Vice President of Supply Chain Management of Souper Salad, Inc. From 2005 to 2008, Mr. Brink served as Senior Director of Purchasing of Pizza Inn, Inc.

Information Regarding the Board of Directors and Committees

Director Attendance

During the fiscal year ended January 1, 2017, our board of directors met or acted by unanimous consent on twelve occasions. During the fiscal year ended January 1, 2017, each of the directors attended 100% of the aggregate number of meetings of the board of directors and of any committees of the board of directors on which they served. We do not have a policy on attendance by directors at our Annual Meeting of Shareholders. Four of our directors attended our 2016 Annual Meeting of Shareholders.

Independence of Directors

As required by the listing standards of NASDAQ, a majority of the members of our board of directors must qualify as "independent," as affirmatively determined by our board of directors. Our board of directors determines director independence based on an analysis of such listing standards and all relevant securities and other laws and regulations regarding the definition of "independent."

Consistent with these considerations, after review of all relevant transactions and relationships between each director, any of his or her family members, and us, our executive officers and our independent registered public accounting firm, the board of directors has affirmatively determined that all of the members of our board of directors are independent pursuant to NASDAQ.

Committees of the Board

The standing committees of our board of directors consist of an Audit Committee, a Compensation Committee, a Corporate Governance and Nominating Committee, and a Finance Committee. Our board of directors may also establish from time to time any other committees that it deems necessary or advisable.

Audit Committee Chair:	**Members:** Elker*, Smith, and Alperin*
	Key Responsibilities:

Stephen P. Elker
(Financial Expert)

Reviews our annual and interim financial statements and reports to be filed with the SEC;

Monitors our financial reporting process and internal control system;

Appoints and replaces our independent outside auditors from time to time, determines their compensation and other terms of engagement and oversees their work;

Oversees the performance of our internal audit function;

Conducts a review of all related party transactions for potential conflicts of interest and approves all such related party transactions;

Establishes procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and

Oversees our compliance with legal, ethical and regulatory matters.

**Denotes director up for election at the 2017 Annual Meeting*

All three current members of the Audit Committee satisfy the independence requirements of Rule 10A-3 of the Exchange Act and Rule 5605 of the NASDAQ listing standards. Each member of our Audit Committee is financially literate. In addition, Mr. Elker serves as our Audit Committee “financial expert” within the meaning of Item 407 of Regulation S-K of the Securities Act and has the financial sophistication required under the NASDAQ listing standards.

The Audit Committee has the sole and direct responsibility for appointing, evaluating and retaining our independent registered public accounting firm and for overseeing their work. All audit services to be provided to us and all permissible non-audit services, other than de minimis non-audit services, to be provided to us by our independent registered public accounting firm are approved in advance by our Audit Committee. During the fiscal year ended January 1, 2017, the Audit Committee met or acted by unanimous consent on four occasions. The Audit Committee has adopted a formal written Audit Committee charter that complies with the requirements of the Exchange Act and the NASDAQ listing standards. A copy of the Audit Committee charter is available on the investor relations section of our website at www.frgi.com.

Audit Committee Report

The Company's management has the primary responsibility for the financial statements and the reporting process, including the Company's system of internal controls and disclosure controls and procedures. The independent registered public accounting firm audits the Company's financial statements and expresses an opinion on the financial statements based on their audit. The Audit Committee oversees on behalf of the board (i) the accounting, financial reporting, and internal control processes of the Company, and (ii) the audits of the financial statements and internal controls of the Company. The Audit Committee operates under a written charter adopted by the board.

The Audit Committee reviews and approves the internal audit plan once a year and receives periodic updates of internal audit activity in meetings held at least quarterly throughout the year. Updates include discussions of audit project results, as well as quarterly assessments of internal controls.

The Audit Committee has met and held discussions with management and Deloitte & Touche LLP ("*Deloitte*"), the Company's independent registered public accounting firm. Management represented to the Audit Committee that the Company's financial statements for the year ended January 1, 2017 were prepared in accordance with generally accepted accounting principles. The Audit Committee reviewed discussed the financial statements with both management and Deloitte. The Audit Committee also discussed with Deloitte the matters required to be discussed by the statement on Auditing Standards No. 61, as amended (AICPA, Professional Standards, Vol. 1. AU section 380), as adopted by the Public Company Accounting Oversight Board (PCAOB). The Audit Committee also reviewed and discussed with Deloitte the firm's independence from the Company and management, including the independent auditor's written disclosures required by Independent Standards Board Standard No. 1 (Independence Standards Board Standard No. 1, *Independence Discussions with Audit Committees*) as adopted by the PCAOB.

The Audit Committee also discussed with Deloitte the overall scope and plans for the audit. The Audit Committee met with Deloitte both with and without management, to discuss the results of their examination, the evaluation of the Company's internal controls and the overall quality of the Company's financial reporting.

Management has completed its annual documentation, testing, and evaluation of the Company's system of internal control over financial reporting in response to the requirements set forth in Section 404 of the Sarbanes-Oxley Act of 2002 and related regulations. The Audit Committee continues to oversee the Company's efforts related to its internal controls.

Based on the foregoing, we have recommended to the board of directors that the Company's audited financial statements be included in its Annual Report on Form 10-K for the year ended January 1, 2017, for filing with the

Securities and Exchange Commission.

Audit Committee

Stephen P. Elker, Chairman

Jack A. Smith

Barry J. Alperin

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Compensation Committee	**Members:** Rauch, Friedman*, Smith, and Twohig
	Key Responsibilities:
Chair:	
Stacey Rauch	Provides oversight on the development and implementation of the compensation programs for our executive officers and outside directors and disclosure relating to these matters; and
	Reviews and approves the compensation of our Chief Executive Officer and our executive officers

**Denotes director up for election at the 2017 Annual Meeting*

The processes and procedures by which the Compensation Committee considers and determines executive officer compensation and outside directors' compensation are described in the Compensation Discussion and Analysis included in this Proxy Statement. During the 2016 fiscal year, the Compensation Committee again retained Pearl Meyer & Partners, LLC, which we refer to as "*Pearl Meyer*", to review the Company's compensation policies, plans, and amounts for the CEO and other executive officers, including the Named Executive Officers. The role of Pearl Meyer in determining or recommending the amount or form of executive and director compensation, the nature and scope of Pearl Meyer's assignment and the material elements of the instructions or directions given to Pearl Meyer with respect to the performance of their duties under the engagement are described in the Compensation Discussion and Analysis included in this Proxy Statement. We believe that the use of an independent compensation consultant provides additional assurance that our compensation programs are reasonable and consistent with our goals and objectives. The Compensation Committee may form one or more subcommittees, each of which shall take such actions as shall be delegated by the Compensation Committee. All of the members of our Compensation Committee are "independent" as defined under Rule 5605 of the NASDAQ listing standards. The Compensation Committee has adopted a formal, written Compensation Committee charter that complies with SEC rules and regulations and the NASDAQ listing standards. During the fiscal year ended January 1, 2017, the Compensation Committee met or acted by unanimous consent on seven occasions. A copy of the Compensation Committee charter is available on the investor relations section of our website at *www.frgi.com.*

Corporate Governance and Nominating Committee	**Members:** Rauch, Friedman*, Elker*, Alperin*, Daraviras, Smith and Twohig
Chair:	**Key Responsibilities:**
Jack A. Smith	
	Establishes criteria for board and committee membership and recommends to our board of directors proposed nominees for election to the board of directors and for membership on committees of the board of directors;

Makes recommendations regarding proposals submitted by our shareholders; and

Makes recommendations to our board of directors regarding corporate governance matters and practices.

**Denotes director up for election at the 2017 Annual Meeting*

All of the members of our Corporate Governance and Nominating Committee are "independent" as defined under Rule 5605 of the NASDAQ listing standards. The Corporate Governance and Nominating Committee has adopted a formal written Corporate Governance and Nominating Committee charter that complies with SEC rules and regulations and the NASDAQ listing standards. During the fiscal year ended January 1, 2017, the Compensation Committee met or acted by unanimous consent on two occasions, and the Special Committee charged with the search for a replacement Chief Executive Officer and President and an additional independent director met or acted by unanimous consent on numerous occasions. A copy of the Corporate Governance and Nominating Committee charter is available on the investor relations section of our website at *www.frgi.com*.

Nominations for the Board of Directors

The Corporate Governance and Nominating Committee of the board of directors considers director candidates based upon a number of qualifications. The qualifications for consideration as a director nominee vary according to the particular area of expertise being sought as a complement to the existing composition of the board. At a minimum, however, the Corporate Governance and Nominating Committee seeks candidates for director who possess:

the highest personal and professional ethics, integrity and values;

the ability to exercise sound judgment;

the ability to make independent analytical inquiries;

willingness and ability to devote adequate time, energy, and resources to diligently perform board and board committee duties and responsibilities; and

a commitment to representing the long-term interests of the shareholders.

In addition to such minimum qualifications, the Corporate Governance and Nominating Committee takes into account the following factors when considering a potential director candidate:

whether the individual possesses specific industry expertise and familiarity with general issues affecting our business; and

whether the person would qualify as an "independent" director under SEC and NASDAQ rules.

The Corporate Governance and Nominating Committee has not adopted a specific diversity policy with respect to identifying nominees for director. However, the Corporate Governance and Nominating Committee takes into account the importance of diversified board membership in terms of the individuals involved and their various experiences and areas of expertise.

The Corporate Governance and Nominating Committee shall make every effort to ensure that the board and its committees include at least the required number of independent directors, as that term is defined by applicable standards promulgated by NASDAQ and/or the SEC. Backgrounds giving rise to actual or perceived conflicts of interest are undesirable. In addition, prior to nominating an existing director for election to the board, the Corporate Governance and Nominating Committee will consider and review such existing director's board and committee attendance and performance, independence, experience, skills, and the contributions that the existing director brings to the board.

The Corporate Governance and Nominating Committee has relied upon third-party search firms to identify director candidates, and may continue to employ such firms in the future if so desired. The Corporate Governance and Nominating Committee also relies upon, receives and reviews recommendations from a wide variety of contacts, including current executive officers, directors, community leaders, and shareholders as a source for potential director candidates. The board retains complete independence in making nominations for election to the board.

The Corporate Governance and Nominating Committee will consider qualified director candidates recommended by shareholders in compliance with our procedures and subject to applicable inquiries. The Corporate Governance and Nominating Committee's evaluation of candidates recommended by shareholders does not differ materially from its evaluation of candidates recommended from other sources. Pursuant to our amended and restated bylaws, as amended, any shareholder may recommend nominees for director not less than 90 days nor more than 120 days in advance of the anniversary date of the immediately preceding annual meeting of shareholders, by writing to Joseph A. Zirkman, Senior Vice President, General Counsel and Secretary, Fiesta Restaurant Group, Inc., 14800 Landmark Boulevard, Suite 500, Dallas, Texas 75254, giving the name, Company stockholdings and contact information of the person making the nomination, the candidate's name, address and other contact information, any direct or indirect holdings of our securities by the nominee, any information required to be disclosed about directors under applicable securities laws and/or stock exchange requirements, information regarding related party transactions with us, the nominee and/or the shareholder submitting the nomination, and any actual or potential conflicts of interest, the nominee's biographical data, current public and private company affiliations, employment history and qualifications and status as "independent" under applicable securities laws and/or stock exchange requirements. All of these communications will be reviewed by our Secretary and forwarded to Jack A. Smith, the Chairman of the Corporate Governance and Nominating Committee, for further review and consideration in accordance with this policy. Any such shareholder recommendation should be accompanied by a written statement from the candidate of his or her consent to be named as a candidate and, if nominated and elected, to serve as a director.

Finance Committee	**Members:** Alperin* and Daraviras Lynn S. Schweinfurth serves as non-board advisor **Key Responsibilities:**
Chair: Barry J. Alperin	Reviews and provides guidance to our board of directors and management about policies relating to the Company's working capital; shareholder dividends and distributions; share repurchases; significant investments; capital stock and debt issuances; material financial strategies and strategic investments; and other transactions or financial issues that management desires to have reviewed by the Finance Committee; and Obtains or performs an annual evaluation of the Finance Committee's performance and makes applicable recommendations to the board of directors.

**Denotes director up for election at the 2017 Annual Meeting*

A copy of the Finance Committee charter is available on the investor relations section of our website at *www.frgi.com*.

Board Leadership Structure and Role in Risk Oversight

Board Leadership

Our board of directors believes that our current model of separate individuals serving as Chairman of the board of directors and as Chief Executive Officer is the appropriate leadership structure for us at this time. The board of directors believes that each of the possible leadership structures for a board has its particular advantages and disadvantages, which must be considered in the context of the specific circumstances, culture and challenges facing a company. The Company does not have a member of our board of directors who is formally identified as the "lead independent director." However the board of directors has determined that having an independent director serve as Chairman of the board of directors is in the best interest of our shareholders at this time. This structure ensures a greater role for the independent directors in the oversight of Fiesta Restaurant Group, active participation of the independent directors in setting agendas and establishing the board of directors' priorities and procedures, including with respect to our corporate governance.

Risk Oversight

Our board of directors believes that oversight of risk management is the responsibility of the full board, with support from its committees and senior management. The board of directors' principal responsibility in this area is to ensure that sufficient resources, with appropriate technical and managerial skills, are provided throughout the Company to identify, assess, and facilitate processes and practices to address material risks. We believe that the current leadership structure enhances the board of directors' ability to fulfill this oversight responsibility, as the Chairman, with the support and input of the Chief Executive Officer, is able to focus the board's attention on the key risks facing us.

Some risks, particularly those relating to potential operating liabilities, the protection against physical loss or damage to our facilities, and the possibility of business interruption resulting from a large loss event, are contained and managed by legal contracts of insurance. Our insurance contracts are reviewed, managed and procured by our Risk Management and Legal departments along with our Chief Financial Officer to optimize their completeness and efficacy. We also have a Risk Committee that meets periodically throughout the year to develop and oversee our risk management program. The Risk Committee's responsibilities include identifying our exposures, developing a risk control program, and establishing a risk financing strategy. Periodic presentations are made to the board to identify and discuss risks and the mitigation of risk.

In addition, the board believes that the Audit Committee plays a particularly important role in overseeing risk. The Audit Committee assesses and oversees business risks as a component of their review of the business and financial

activities of the Company.

Codes of Ethics

We have adopted written codes of ethics applicable to our directors, officers, and employees in accordance with the rules of the SEC and the NASDAQ listing standards. With respect to our Code of Ethics for Executives and Principal Financial Employees, our policy requires covered employees to execute an annual certification confirming that they understand and will comply with the Code. We make our codes of ethics available on the investor relations section of our website at *www.frgi.com*. We will disclose on our website amendments to, or waivers from, our codes of ethics in accordance with all applicable laws and regulations.

Section 16(a) Beneficial Ownership Reporting Compliance

Based upon a review of the filings furnished to us pursuant to Rule 16a-3(e) promulgated under the Exchange Act, and on representations from our executive officers and directors and persons, if any, who beneficially own more than 10% of our common stock, all filing requirements of Section 16(a) of the Exchange Act were complied with in a timely manner during the fiscal year ended January 1, 2017 other than Statement of Changes of Beneficial Ownership on Form 4 filed by each of Timothy P. Taft, Lynn Schweinfurth, Joseph A. Zirkman, Danny Meisenheimer, Todd Coerver, John Todd and Cheri Kinder on March 7, 2016 reporting the grant of restricted stock on March 2, 2016.

Shareholder Communications with the Board of Directors

Any shareholder or other interested party who desires to communicate with our Chairman of the board of directors or any of the other members of the board of directors may do so by writing to: Board of Directors, c/o Stacey Rauch, Chairman of the Board of Directors, Fiesta Restaurant Group, Inc., 14800 Landmark Boulevard, Suite 500, Dallas, Texas 75254. Communications may be addressed to the Chairman of the board, an individual director, a board committee, the non-management directors, or the full board. Communications will then be distributed to the appropriate directors unless the Chairman determines that the information submitted constitutes “spam,” pornographic material, and/or communications offering to buy or sell products or services.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table provides information regarding beneficial ownership of our common stock as of April 10, 2017 by:

each person known by us to beneficially own more than 5% of all outstanding shares of our common stock;

each of our directors, nominees for director, and Named Executive Officers (as set forth in “Executive Compensation-Summary Compensation Table” herein) individually; and

all of our directors and executive officers as a group.

27,063,800 shares of our common stock were outstanding on April 10, 2017.

Except as otherwise indicated, to our knowledge, all persons listed below have sole voting power and investment power and record and beneficial ownership of their shares, other than to the extent that authority is shared by spouses under applicable law.

The information contained in this table reflects “beneficial ownership” as defined in Rule 13d-3 of the Exchange Act. Except as otherwise indicated, the address for each beneficial owner is c/o Fiesta Restaurant Group, Inc., 14800 Landmark Boulevard, Suite 500, Dallas, Texas 75254.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class	
Wasatch Advisors, Inc. (1)	3,194,095	11.8	%
BlackRock Inc. (2)	3,072,291	11.4	%
JCP Investment Partnership, LP et al (3)	2,272,161	8.4	%
The Vanguard Group, Inc. (4)	2,139,225	7.9	%
Morgan Stanley (5)	1,349,054	5.0	%

Morgan Stanley Investment Management			
Danny K. Meisenheimer	31,936	*	
Timothy P. Taft (6)	177,041	*	
Richard C. Stockinger	79,235	*	
Lynn S. Schweinfurth	88,946	*	
Joseph A. Zirkman	128,614	*	
Joseph Brink	17,773	*	
John Todd (7)	14,054	*	
Todd Coerver (8)	28,684	*	
Paul E. Twohig	9,820	*	
Stacey Rauch	14,262	*	
Brian P. Friedman (9)	1,068,349	3.9	%
Stephen P. Elker	14,262	*	
Barry J. Alperin	13,277	*	
Nicholas Daraviras	11,609	*	
Jack A. Smith	40,452	*	
All directors and executive officers as a group (10)	1,518,535	5.6	%

*Less than one percent

(1) Information was obtained from a Schedule 13G/A filed on February 28, 2017 with the SEC. The address for Wasatch Advisors, Inc. is 505 Wakara Way, Salt Lake City, Utah 84108.

(2) Information was obtained from a Schedule 13G/A filed on January 12, 2017 with the SEC. The address for BlackRock Inc. is 55 East 52nd Street, New York, New York 10022.

(3) Information was obtained from a Schedule 13D/A filed on January 20, 2016 with the SEC by JCP Investment Partnership, LP, which we refer to as "*JCP Partnership*", JCP Single-Asset Partnership, LP, which we refer to as the "*JCP Single-Asset*", JCP Investment Partners, LP, which we refer to as "*JCP Partners*", JCP Investment Holdings, LLC, which we refer to as "*JCP Holdings*", JCP Investment Management, LLC, which we refer to as "*JCP Management*", James, C. Pappas, BLR Partners LP, which we refer to as "*BLR Partners*", BLRPart, LP, which we refer to as "*BLRPart LP*", BLRGP Inc., which we refer to as "*BLRGP*", Fondren Management, LP, which we refer to as "*Fondren Management*", FMLP Inc., which we refer to as "*FMLP*", Bradley L. Radoff, Bandera Master Fund L.P., which we refer to as "*Bandera Master Fund*", Bandera Partners LLC, which we refer to as "*Bandera Partners*", Gregory Bylinsky, Jefferson Gramm, Lake Trail Managed Investments LLC, which we refer to as "*Lake Trail Fund*", Lake Trail Capital LP, which we refer to as "*Lake Trail Capital*", Lake Trail Capital GP LLC, which we refer to as "*Lake Trail GP*", Thomas W. Purcell, Jr., Joshua Schechter and John B. Morlock, which we refer to collectively as the "*Dissident Group*". JCP Partnership beneficially owns our shares as follows: (a) Sole Voting Power: 455,012 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 455,102 and (d) Shared Dispositive Power: 0. JCP Single-Asset beneficially owns our shares as follows: (a) Sole Voting Power: 219,096 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 219,096 and (d) Shared Dispositive Power: 0. JCP Partners, as general partner of each of JCP Partnership and JCP Single-Asset, may be deemed the beneficial owner of the (i) 455,012 shares owned by JCP Partnership and (ii) 219,096 shares owned by JCP Single-Asset. JCP Partners beneficially owns our shares as follows: (a) Sole Voting Power: 674,108 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 674,108 and (d) Shared Dispositive Power: 0. JCP Holdings, as the general partner of JCP Partners, may be deemed the beneficial owner of the (i) 455,012 shares owned by JCP Partnership and (ii) 219,096 shares owned by JCP Single-Asset. JCP Holdings beneficially owns our shares as follows: (a) Sole Voting Power: 674,108 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 674,108 and (d) Shared Dispositive Power: 0. JCP Management, as the investment manager of each of JCP Partnership and JCP Single-Asset, may be deemed the beneficial owner of the (i) 455,012 shares owned by JCP Partnership and (ii) 219,096 shares owned by JCP Single-Asset. JCP Management beneficially owns our shares as follows: (a) Sole Voting Power: 674,108 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 674,108 and (d) Shared Dispositive Power: 0. Mr. Pappas, as the managing member of JCP Management and sole member of JCP Holdings, may be deemed the beneficial owner of the (i) 455,012 shares owned by JCP Partnership and (ii) 219,096 shares owned by JCP Single-Asset. Mr. Pappas beneficially owns our shares as follows: (a) Sole Voting Power: 674,108 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 674,108 and (d) Shared Dispositive Power: 0. BLR Partners beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. BLRPart LP, as the general partner of BLR Partners, may be deemed the beneficial owner of the 600,000 shares owned by BLR Partners. BLRPart LP beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. BLRGP, as the general partner of BLRPart LP, may be deemed the beneficial owner of the 600,000 shares owned by BLR Partners. BLRGP beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Fondren Management, as the investment manager of BLR Partners, may be deemed the beneficial owner of the 600,000 shares owned by BLR Partners. Fondren Management beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. FMLP, as the general partner of Fondren Management, may be deemed the beneficial owner of the 600,000 shares owned by BLR Partners. FMLP beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Mr. Radoff, as the sole shareholder and sole director of each of BLRGP and FMLP, may be deemed the beneficial owner of the 600,000 shares owned by BLR Partners. Mr. Radoff beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Bandera Master Fund beneficially owns our shares as follows: (a) Sole Voting Power:

378,654 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 378,654 and (d) Shared Dispositive Power: 0. Bandera Partners, as the investment manager of Bandera Master Fund, may be deemed the beneficial owner of the 378,654 shares owned by Bandera Master Fund. Bandera Partners beneficially owns our shares as follows: (a) Sole Voting Power: 378,654 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 378,654 and (d) Shared Dispositive Power: 0. Each of Mr. Bylinsky and Mr. Gramm, as the managing partners, managing directors and portfolio managers of Bandera Partners, may be deemed the beneficial owner of the 378,654 shares owned by Bandera Master Fund. Each of Mr. Bylinsky and Mr. Gramm beneficially owns our shares as follows: (a) Sole Voting Power: 378,654 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 378,654 and (d) Shared Dispositive Power: 0. Lake Trail Fund beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Lake Trail Capital, as the manager and investment manager of Lake Trail Fund, may be deemed the beneficial owner of the 600,000 shares owned by Lake Trail Fund. Lake Trail Capital beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Lake Trail GP, as the general partner of Lake Trail Capital, may be deemed the beneficial owner of the 600,000 shares owned by Lake Trail Fund. Lake Trail GP beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Mr. Purcell, as the sole member of Lake Trail GP, may be deemed the beneficial owner of the 600,000 Shares owned by Lake Trail Fund. Mr. Purcell beneficially owns our shares as follows: (a) Sole Voting Power: 600,000 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 600,000 and (d) Shared Dispositive Power: 0. Mr. Schechter beneficially owns our shares as follows: (a) Sole Voting Power: 17,700 (b) Shared Voting Power: 1,700, (c) Sole Dispositive Power: 17,700 and (d) Shared Dispositive Power: 1,700. Mr. Morlock beneficially owns our shares as follows: (a) Sole Voting Power: 0 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 0 and (d) Shared Dispositive Power: 0. The Dissident Group, as members of a "group" for the purposes of Section 13(d)(3) of the Exchange Act may be deemed the beneficial owner of our shares directly owned by the other members of the Dissident Group. Each member of the Dissident Group disclaims beneficial ownership of such shares except to the extent of his or its pecuniary interest therein. The address of the principal office of each of JCP Partnership, JCP Single-Asset, JCP Partners, JCP Holdings, JCP Management and Mr. Pappas is 1177 West Loop South, Suite 1650, Houston, Texas 77027. The address of the principal office of each of BLR Partners, BLRPart LP, BLRGP, Fondren Management, FMLP and Mr. Radoff is 1177 West Loop South, Suite 1625, Houston, Texas 77027. The address of the principal office of each of Bandera Master Fund, Bandera Partners and Messrs. Bylinsky and Gramm is 50 Broad Street, Suite 1820, New York, New York 10004. The address of the principal office of each of Lake Trail Fund, Lake Trail Capital, Lake Trail GP and Mr. Purcell is 400 Park Avenue, 21st Floor, New York, New York 10022. The address of the principal office of Mr. Schechter is 302 South Mansfield Avenue, Los Angeles, California 90036. The address of the principal office of Mr. Morlock is 1328 Dublin Road, Columbus, Ohio 43215.

(4) Information was obtained from a Schedule 13G/A filed on February 10, 2017 with the SEC. The address for The Vanguard Group, Inc. is 100 Vanguard Blvd. Malvern, PA 19355.

(5) Information was obtained from a Schedule 13G/A filed on February 10, 2017 with the SEC. Morgan Stanley beneficially owns our shares as follows: (a) Sole Voting Power: 1,348,354 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 0 and (d) Shared Dispositive Power: 1,349,354. Morgan Stanley Investment Management Inc. beneficially owns our shares as follows: (a) Sole Voting Power: 1,348,354 (b) Shared Voting Power: 0, (c) Sole Dispositive Power: 0 and (d) Shared Dispositive Power: 1,349,354. The address of the principal office of each of Morgan Stanley and Morgan Stanley Investment Management Inc. is 1585 Broadway, New York, New York 10036.

(6) Mr. Taft served as our Chief Executive Officer and President and a member of our board of directors until September 30, 2016. Information was obtained from a Statement of Changes in Beneficial Ownership on Form 4 filed March 7, 2016 with the SEC. The address of Mr. Taft is 5606 Palomar Lane, Dallas, Texas 75229.

(7) Mr. Todd served as our Group Vice President, Chief Development Officer until January 1, 2017. Information was obtained from a Statement of Changes in Beneficial Ownership on Form 4 filed August 24, 2016 with the SEC. The address of Mr. Todd is 1080 W. Bethel Road, Coppell, Texas 75019.

(8) Mr. Coerver served as our Chief Operating Officer, Taco Cabana until October 20, 2016. Information was obtained from a Statement of Changes in Beneficial Ownership on Form 4 filed March 7, 2016 with the SEC. The address of Mr. Coerver is 700 12th Street, #220, Golden, Colorado 80401.

(9) Information was obtained from a Statement of Changes in Beneficial Ownership on Form 4 filed April 30, 2015 with the SEC. Includes 1,007,000 shares of Common Stock held by Leucadia, 28,668 shares of Common Stock held by 2055 Partners L.P., which we refer to as "*2055 Partners*", and 32,681 shares of our Common Stock held directly by Mr. Friedman. Mr. Friedman is the President and a director of Leucadia. Mr. Friedman disclaims beneficial ownership over our shares held by Leucadia except to the extent of his indirect pecuniary interest. Mr. Friedman is the general partner of 2055 Partners and, in such capacity, may be deemed to beneficially own the 28,668 shares of our Common Stock beneficially owned by 2055 Partners. The address of Mr. Friedman is 520 Madison Avenue, 11th Floor, New York, New York 10022.

(10) Includes 1,007,000 shares of Common Stock held by Leucadia and 28,668 shares of Common Stock held by 2055 Partners as reported in footnote (9) above.

Equity Compensation Plan

The following table summarizes our 2012 Stock Incentive Plan, which is the equity compensation plan under which our common stock may be issued as of January 1, 2017. Our shareholders have approved the Plan.

	Number of securities	Weighted-average	Number of securities

	to be issued upon exercise of outstanding options, warrants, and rights	exercise price of outstanding options	remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	—	—	2,169,321
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	2,169,321

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CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Related Party Transaction Procedures

The board of directors has assigned responsibility for reviewing related party transactions to our Audit Committee. The board of directors and the Audit Committee have adopted a written policy pursuant to which certain transactions between us or our subsidiaries and any of our directors or executive officers must be submitted to the Audit Committee for consideration prior to the consummation of the transaction as required by the rules of the SEC. The Audit Committee reports to the board of directors on all related party transactions considered.

Family Relationships

There are no family relationships between any of our executive officers or directors.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The purpose of this Compensation Discussion & Analysis, which we refer to as the "*CD&A*", is to provide relevant information to shareholders regarding the Company's executive compensation processes, procedures, plan designs, and practices with respect to its executive officers named in the Summary Compensation Table, which we refer to each as a "*Named Executive Officer*" or "*NEO*", for 2016. The following are the Company's NEOs for 2016:

Mr. Timothy P. Taft – Former Chief Executive Officer and President (until September 30, 2016)

Mr. Danny K. Meisenheimer – Senior Vice President and Chief Operating Officer (since February 28, 2017); Former Interim Chief Executive Officer and President (October 1, 2016 through February 28, 2017) and former Chief Operating Officer, Pollo Tropical (until September 30, 2016)

Ms. Lynn S. Schweinfurth – Senior Vice President, Chief Financial Officer, and Treasurer

Mr. Joseph A. Zirkman – Senior Vice President, General Counsel, and Secretary

Mr. John Todd – Former Chief Development Officer (until January 1, 2017)

Mr. Joseph Brink – Chief Procurement Officer

Mr. Todd Coerver – Former Chief Operating Officer, Taco Cabana (until October 20, 2016)

Executive Summary

The key objective of the executive compensation program is to align executive pay with performance in a straightforward manner that promotes the recruitment and retention of our executives. Accordingly, the majority of the compensation for our NEOs is at-risk and based primarily on the Company's performance. Our executives will receive larger rewards when performance objectives are exceeded and conversely will receive lower or no rewards when performance falls below targeted levels.

Fiesta Restaurant Group is focused on growing the Company and building shareholder value. To help accomplish these goals, we attract, retain, and reward executive talent with a compensation plan comprised of three components: base salaries, annual cash incentive compensation, and equity compensation in the form of restricted stock and performance-based restricted stock units.

2016 Performance Results

Our 2016 Company performance results included:

Total revenues increased 3.5% to $711.8 million. Excluding the extra fiscal week in 2015, total revenues increased 5.4%*;*

Same Restaurant Sales, which we refer to as "SRS" decreased 2.0% in 2016 on a consolidated basis*;*

Comparable restaurant sales at Pollo Tropical decreased 1.6% and comparable restaurant transactions decreased 3.1%, partially due to sales cannibalization that negatively impacted comparable restaurant transactions by approximately 1.5%;

Comparable restaurant sales at Taco Cabana decreased 2.5% and comparable restaurant transactions decreased 3.6%;

Adjusted EBT (as defined below) in 2016 decreased to $27.5 million compared to Adjusted EBT of $62.4 million in 2015;

Adjusted EPS (as defined below) in 2016 declined to $0.68 compared to Adjusted EPS of $1.48 in 2015;

32 Company-owned Pollo Tropical and four Company-owned Taco Cabana restaurants were opened; and

14 Company-owned Pollo Tropical restaurants were reimaged.

The Company has made several key decisions in 2016 that we believe will benefit future financial performance of the Company but some of which have resulted in increased near term headwinds and costs. These decisions include:

Initiation of a comprehensive review of the Company's strategic plan;

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Suspension of the Taco Cabana separation process;

Suspension of new Pollo Tropical restaurant development in emerging markets that contributed approximately $4.8 million of pre-tax operating losses to results in 2016;

Closure of 10 underperforming Pollo Tropical restaurants in emerging markets; and

Upon the retirement of the Company’s former Chief Executive Officer and President, Tim Taft, initiated a search for a new Chief Executive Officer and a new member of the Board of Directors designed to strengthen the Company and its governance which resulted in the appointment of Richard Stockinger as Chief Executive Officer and President of the Company effective February 28, 2017 and the appointment of Paul E. Twohig to the Company’s board of directors effective February 28, 2017.

We believe the Company’s compensation results for 2016 were aligned with the Company’s financial and strategic results for the year. SRS and Adjusted EBT were negatively impacted by factors that include impairment and other lease charges, challenging market conditions impacting the restaurant industry, sales cannibalization from new Company-owned restaurants on existing Company-owned restaurants at Pollo Tropical, and Company-owned Pollo Tropical restaurant performance in emerging markets. As a result, there were no short-term cash incentive payouts given the Company’s performance relative to budget for SRS and Adjusted EBT. In addition, The Company did not achieve at least 75% of its EBT target for 2016 and, accordingly, the first 25% of the 2016 restricted stock awards and the second 25% of the 2015 restricted stock awards to the NEOs did not vest and were forfeited.

Significant Portion of Targeted CEO Compensation is At-Risk

72% of CEO pay is at-risk which incentivizes executive performance to drive shareholder value

The Role of Shareholder Feedback and Vote Results

The Company’s board of directors, Compensation Committee, and management value the opinions of the Company’s shareholders. The Company is open to receiving feedback from shareholders and provides shareholders with the opportunity to cast an advisory vote to approve NEO compensation every year, or Say-on-Pay. The Compensation

Committee considers any feedback it receives from shareholders, as well as the outcome of the vote, when making compensation decisions for NEOs. For the Say-on-Pay proposal at the 2016 Annual Meeting, more than 99% of the shares cast on the proposal were voted in favor of the proposal. The Compensation Committee believes that this evidences the Company's shareholders' support for its approach to executive compensation. The Compensation Committee will continue to consider shareholder feedback and the outcome of the Company's Say-on-Pay votes when making future compensation decisions for its NEOs.

Executive Compensation Components

Base Salary

The Compensation Committee reviews and considers salary increases of our NEOs on an annual basis, taking into consideration factors such as the Company's compensation philosophy and strategy, the Company's performance, individual executive performance and tenure, internal equity among executives, and competitive market pay levels. In 2016, the Compensation Committee increased Mr. Meisenheimer's salary by 14.4% and Mr. Brink's salary by 8%. No other NEOs received a base salary increase in 2016 and no NEOs received a base salary increase in 2017. Mr. Meisenheimer's annual base salary was increased effective October 1, 2016 when he became Interim Chief Executive Officer and President.

Short-Term Incentive

The Short-Term Incentive Program creates a variable pay opportunity tied to corporate, brand, and individual executive performance. The purpose of the Short-Term Incentive Program is to align annual incentive payments with annual performance goals that are aligned with our strategy to create sustainable value for shareholders. For the Company's short-term incentive compensation program in 2016, all NEOs were eligible to receive a cash bonus tied to the achievement of SRS, Adjusted Earnings Before Tax, which we refer to as "*Adjusted EBT*", and individual goals and objectives, which we refer to as "*MBO*". SRS is referred to as comparable restaurant sales in the Company's Annual Report on Form 10-K for the fiscal year ended January 1, 2017 filed with the SEC on February 27, 2017, which we refer to as the "2016 Form 10-K". Adjusted EBT refers to income before taxes (which is set forth in Note 11 to the Company's consolidated financial statements included in the 2016 Form 10-K).

For 2016, each NEO had a threshold, target, and maximum award opportunity for SRS and Adjusted EBT, where the threshold award opportunity was equal to 50% of target and the maximum award opportunity was equal to 150% of target. For 2016, each NEO also had an award opportunity for MBO performance measures ranging from 0% to 100% of the target award opportunity, subject to achievement of at least 75% of budgeted EBT target.

The following table sets forth the target weighting applicable to each measure for each NEO in 2016:

		FRGI Consolidated		Pollo Tropical		Taco Cabana			
Executive	Position Title	SRS	Adjusted EBT	SRS	Adjusted EBT	SRS	Adjusted EBT	Individual MBO	Total % of Target
Timothy P. Taft	Former CEO & President	20.0%	60.0 %	0.0 %	0.0 %	0.0 %	0.0 %	20.0 %	100.0%
Danny K. Meisenheimer	Senior Vice President and Chief Operating Officer, Former Interim CEO & President (1)	2.5 %	7.5 %	24.5%	45.5 %	0.0 %	0.0 %	20.0 %	100.0%
Lynn S. Schweinfurth	Senior Vice President, CFO & Treasurer	20.0%	60.0 %	0.0 %	0.0 %	0.0 %	0.0 %	20.0 %	100.0%
Joseph A. Zirkman	Senior Vice President, GC & Secretary	20.0%	60.0 %	0.0 %	0.0 %	0.0 %	0.0 %	20.0 %	100.0%
John Todd		20.0%	60.0 %	0.0 %	0.0 %	0.0 %	0.0 %	20.0 %	100.0%

	Former Group Vice President, Chief Development Officer								
Joseph Brink	Chief Procurement Officer	20.0 %	60.0 %	0.0 %	0.0 %	0.0 %	0.0 %	20.0 %	100.0 %
Todd Coerver	Former COO, Taco Cabana	2.5 %	7.5 %	0.0 %	0.0 %	24.5 %	45.5 %	20.0 %	100.0 %

(1) The target weighting applicable to each measure in the table above with respect to Mr. Meisenheimer reflects his role as Chief Operating Officer, Pollo Tropical from January 4, 2016 until September 29, 2016. Upon assuming the position of Interim Chief Executive Officer and President beginning October 1, 2016 through January 1, 2017, the target weightings applicable to each measure are as follows: FRGI Consolidated SRS 2 0.0%, Fiesta Consolidated Adjusted EBT 60.0%; Pollo Tropical SRS 0.0%, Pollo Tropical Adjusted EBT 0.0%; Taco Cabana SRS 0.0%, Taco Cabana Adjusted EBT 0.0% and Individual MBO 20.0%, totaling 100% of Target.

The following table sets forth the (a) threshold award opportunity amount, target award opportunity amount, the maximum award opportunity amount with respect to SRS and Adjusted EBT for FRGI Consolidated, Pollo Tropical, and Taco Cabana, (b) actual SRS and Adjusted EBT amounts achieved in 2016 for FRGI Consolidated, Pollo Tropical, and Taco Cabana, and (c) achievement percentage of actual SRS and Adjusted EBT amounts achieved in 2016 for FRGI Consolidated, Pollo Tropical, and Taco Cabana relative to the target award opportunity amount:

	Threshold	Target	Maximum	Actual	Achievement Percentage
FRGI Consolidated SRS	2.7 %	3.0 %	3.3 %	(2.0)%	(66.7)%
Pollo Tropical SRS(1)	2.3 %	2.6 %	2.9 %	(1.6)%	(61.5)%
Taco Cabana SRS(2)	3.2 %	3.5 %	3.9 %	(2.5)%	(71.4)%

	Threshold $ millions	Target $ millions	Maximum $ millions	Actual $ millions	Achievement Percentage
FRGI Consolidated Adjusted EBT	$ 61.7	$ 68.6	$ 75.5	$ 27.5	40.1 %
Pollo Tropical Adjusted EBT(1)	$ 35.3	$ 39.2	$ 43.1	$ 6.2	15.8 %
Taco Cabana Adjusted EBT(2)	$ 26.5	$ 29.4	$ 32.3	$ 21.3	72.3 %

(1) The SRS and Adjusted EBT amounts for our Pollo Tropical brand are only applicable to Mr. Meisenheimer.

(2) The SRS and Adjusted EBT amounts for our Taco Cabana brand are only applicable to Mr. Coerver. The minimum achievement percentage of 90% would result in a payment of 50% of target while an achievement percentage of 110% or greater would result in a maximum payment of 150% for each of SRS and Adjusted EBT and multiplied

by the target weighting. Straight line interpolation between threshold and target achievement and between target and maximum achievement will be used in the payout calculation.

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In 2016, Adjusted EBT was adjusted to exclude $1.6 million of financial and legal fees primarily related to a review of strategic alternatives, $0.5 million of office restructuring and relocation costs and $0.3 in legal settlement costs associated with a class action litigation, partially offset by benefits related to litigation matters. Adjusted EPS was adjusted $0.06 to exclude the same items. In 2015, Adjusted EBT was adjusted to exclude $1.7 million of fees and other costs related to a class action lawsuit settlement plus legal and other fees incurred in defending the action, and $0.1 million of costs related to legal and tax accounting professional fees associated with the review of strategic alternatives for the Company's Taco Cabana brand. In 2015, Adjusted EPS was adjusted $0.04 to exclude the same items. No adjustments were made to Adjusted EBT in 2014.

The following table sets forth the target short-term incentive opportunity for each NEO for 2016, as well as the actual 2016 short-term incentive earned based on results:

Executive	Position Title	Base Salary	Target Short-Term Incentive % Salary	Target Short-Term Incentive $ Value	Actual Short-Term Incentive % Target	Actual Short-Term Incentive $ Value
Timothy P. Taft	Former Chief Executive Officer & President	$550,000	90.0 %	$495,000	0.0 %	$ 0
Danny K. Meisenheimer	Senior Vice President and Chief Operating Officer, Former Interim Chief Executive Officer & President (1)	$295,333	60.0 %	$177,200	0.0 %	$ 0
Lynn S. Schweinfurth	Senior Vice President, Chief Financial Officer & Treasurer	$352,000	60.0 %	$211,200	0.0 %	$ 0
Joseph A. Zirkman	Senior Vice President, General Counsel & Secretary	$326,700	60.0 %	$196,020	0.0 %	$ 0
John Todd	Former Group Vice President, Chief Development Officer	$330,000	60.0 %	$198,000	0.0 %	$ 0
Joseph Brink	Chief Procurement Officer	$200,232	40.0 %	$80,093	0.0 %	$ 0
Todd Coerver	Former Chief Operating Officer, Taco Cabana	$288,400	60.0 %	$173,040	0.0 %	$ 0

(1) The Base Salary and Target Short-term Incentive $ Value amounts in the table above with respect to Mr. Meisenheimer were prorated based on Mr. Meisenheimer's role as Chief Operating Officer, Pollo Tropical from January 4, 2016 until September 29, 2016 and as Interim Chief Executive Officer and President from October 1, 2016 until January 1, 2017.

The consolidated and brand SRS and Adjusted EBT results were formulaic calculations based on actual performance in 2016 relative to budgeted target amounts. The individual MBO results were based on an assessment of each

individual's accomplishments relative to pre-determined goals for the year. The Compensation Committee assessed the individual performance of each NEO. The determination of whether MBO goals and objectives were met by each NEO was not entirely formulaic, objective, or quantifiable; rather, the individual performance considerations included some factors (among others) that were subjective judgments in connection with the compensation decision.

SRS and Adjusted EBT were negatively impacted by factors that include impairment and other lease charges, challenging market conditions impacting the restaurant industry, sales cannibalization from new Company-owned restaurants on existing Company-owned restaurants at Pollo Tropical, and Company-owned Pollo Tropical restaurant performance in emerging markets. As a result, there were no short-term cash incentive payouts given the Company's performance relative to budget for SRS and Adjusted EBT.

Long-Term Incentive

The Company has adopted a long-term incentive program that provides the opportunity for annual equity grants to the NEOs pursuant to the Plan. The purpose of the long-term incentive program is to align long-term pay with long-term performance goals by providing stock-based compensation that will reward executives for creating sustainable shareholder value. The following sets forth the target long-term incentive grant date value (based on the closing price of the common stock on the date of grant) for each NEO for 2016:

Executive	**Position Title**	**Target Long-Term Incentive $ Value**
Timothy P. Taft	Former Chief Executive Officer & President	$ 950,000
Danny K. Meisenheimer	Senior Vice President and Chief Operating Officer, Former Interim Chief Executive Officer & President	$ 275,000
Lynn S. Schweinfurth	Senior Vice President, Chief Financial Officer & Treasurer	$ 450,000
Joseph A. Zirkman	Senior Vice President, General Counsel & Secretary	$ 225,000
John Todd	Former Group Vice President, Chief Development Officer	$ 200,000
Joseph Brink	Chief Procurement Officer	$ 100,000
Todd Coerver	Former Chief Operating Officer, Taco Cabana	$ 175,000

The Compensation Committee has established a policy to provide that restricted stock and performance stock unit grants to employees, including the NEOs, which are determined pursuant to the target long-term incentive grant date value, will be granted annually in February or March on a grant date which is five business days following the announcement of the Company’s financial results for the prior fiscal year with annual vesting dates linked to the grant date. Accordingly, the measurement of the value of any restricted stock grant or performance stock unit grant would be based upon the price of our common stock at the close of business on such grant date. Because the Compensation Committee’s policy is to grant restricted stock and performance stock units on a fixed date, the Compensation Committee may have previously, or may in the future grant restricted stock at a time when it, as well as the senior management, may be aware of material non-public information that, once made public, could either have a positive or negative effect on the price of our common stock.

Restricted Stock

The use of restricted stock creates stock ownership opportunities and retention strength. The 2016 restricted stock grants represented 50% of each NEO’s annual equity target opportunity. The 2016 restricted stock awards vest 25% on each anniversary date over four years if the minimum performance condition for vesting is met each year. This

performance condition requires the Company to achieve at least 75% of its EBT target each year in order for the restricted stock to vest at the time the service condition is satisfied. This performance condition prevents shares from vesting at the vesting date if the Company did not achieve at least 75% of its EBT target for the preceding year. The Company did not achieve at least 75% of its EBT target for 2016 and, accordingly, the first 25% of the 2016 restricted stock awards and the second 25% of the 2015 restricted stock awards to the NEOs did not vest and were forfeited in February and March 2017 as follows: Mr. Meisenheimer – 1,505 shares, Ms. Schweinfurth – 2,462 shares, Mr. Zirkman – 1,231 shares, Mr. Todd – 1,095 shares and Mr. Brink – 355 shares.

Performance Stock Units

The use of performance stock units creates alignment between long-term pay and long-term company performance. The 2016 performance stock unit grants represented 50% of each NEO's total annual equity target opportunity. The performance criterion for the performance stock units is three-year cumulative Adjusted EPS. A three-year cumulative Adjusted EPS goal of $5.80 was approved by the Compensation Committee. The potential payout under the 2016 grant of performance stock units will be in 2019 based on the Company's financial results for the three year period including 2016, 2017, and 2018.

Payouts (consisting of shares of common stock issued under the Plan) ranging from 50%-200% are earned based on a sliding scale of performance between 90%-120% of the Adjusted EPS goal. Performance below 90% of goal results in no payout.

The potential payout under the 2016 grant of performance stock units will be in 2019 based on the Company's financial results for the three year period including 2016, 2017, and 2018.

The following table sets forth the threshold, target, and maximum performance stock unit grant levels for each NEO for 2016, with the Target # of Shares being the actual grant of performance stock units for 2016:

Executive	Position Title	Threshold # of Shares	Target # of Shares	Maximum # of Shares
Timothy P. Taft	Former Chief Executive Officer & President	6,738	13,476	26,952
Danny K. Meisenheimer	Senior Vice President and Chief Operating Officer, Former Interim Chief Executive Officer & President	1,951	3,901	7,802
Lynn S. Schweinfurth	Senior Vice President, Chief Financial Officer & Treasurer	3,192	6,383	12,766
Joseph A. Zirkman	Senior Vice President, General Counsel & Secretary	1,596	3,192	6,384
John Todd	Former Group Vice President, Chief Development Officer	1,419	2,837	5,674
Joseph Brink	Chief Procurement Officer	710	1,419	2,838
Todd Coerver	Former Chief Operating Officer, Taco Cabana	1,242	2,483	4,966

For the above table, the number of shares was calculated using the grant date stock price of $35.25.

The following table sets forth the threshold, target, and maximum three-year Adjusted EPS benchmarks established by the Compensation Committee for the 2016 awards of performance stock units as well as the potential payout of shares that are determined by the actual, cumulative Adjusted EPS achieved by the Company.

	Cumulative 3-Year Adjusted EPS	% Adjusted Target Achieved	% Payout of Target Performance Stock Units
Threshold	$ 5.06	90 %	50 %
Target	$ 5.62	100 %	100 %
Maximum	$ 6.74	120 %	200 %

Retention Bonus

In November 2016, the Company entered into agreements with certain key employees including several of our NEO's that provided for retention bonuses and (except in the case of Mr. Brink) severance arrangements. The purpose of the such agreements was to ensure continuity in our senior management team by increasing the likelihood that such key

senior executives would remain employed with the Company while the Company was engaged in searching for a new Chief Executive Officer and after a new Chief Executive Officer was appointed.

The Company entered into an agreement, which we refer to as the "*Schweinfurth Agreement*", with Ms. Schweinfurth on November 4, 2016 which are further described on pages 39 and 47 of this Proxy Statement. Pursuant to the Schweinfurth Agreement, Ms. Schweinfurth was entitled to a retention bonus payment of $150,000 which was paid in February 2017 subject to the provisions of the Schweinfurth Agreement.

The Company entered into an agreement, which we refer to as the "*Meisenheimer Agreement*" with Mr. Meisenheimer on November 4, 2016 which is further described on pages 40 and 46 of this Proxy Statement. Pursuant to the Meisenheimer Agreement, Mr. Meisenheimer was entitled to a retention bonus payment of $175,000 which was paid in February 2017 subject to the provisions of the Meisenheimer Agreement.

The Company entered into an agreement, which we refer to as the "*Zirkman Agreement*" with Mr. Zirkman on November 4, 2016 which is further described on pages 40 and 48 of this Proxy Statement. Pursuant to the Zirkman Agreement, Mr. Zirkman was entitled to a retention bonus payment of $100,000 which was paid in February 2017 subject to the provisions of the Zirkman Agreement.

The Company entered into a Retention Bonus Agreement, which we refer to as the "*Brink Agreement*" with Mr. Brink on November 9, 2016 which is further described on page 41 of this Proxy Statement. Pursuant to the Brink Agreement, Mr. Brink was entitled to a retention bonus payment of $40,000 which was paid in February 2017 subject to the provisions of the Brink Agreement.

Additional Compensation Policies and Practices

Executive Stock Ownership Guidelines

Executives of the Company are expected to acquire and continue to hold shares of the Company's common stock having an aggregate market value which equals or exceeds a multiple of base salary as outlined below within five years of being named an Executive.

The following sets forth the minimum stock ownership level for each NEO:

Executive	Position Title	Salary Multiple
Timothy P. Taft	Former Chief Executive Officer & President	3x
Danny K. Meisenheimer	Senior Vice President and Chief Operating Officer, Former Interim Chief Executive Officer & President	1x
Lynn S. Schweinfurth	Senior Vice President, Chief Financial Officer & Treasurer	1x
Joseph A. Zirkman	Senior Vice President, General Counsel & Secretary	1x
John Todd	Former Group Vice President, Chief Development Officer	1x
Joseph Brink	Chief Procurement Officer	1x
Todd Coerver	Former Chief Operating Officer, Taco Cabana	1x

Only actual shares owned by each executive, including direct and indirect ownership as reported to the SEC, count toward compliance with these guidelines.

Compensation Clawback Policy

The Company has adopted a compensation clawback policy. The NEOs are covered by the policy, which enables the board of directors to seek repayment of incentive compensation that was paid based on financial results that are subsequently restated whereby the amount of incentive compensation that would have been awarded or earned based on the restated financial results is lower than what was paid based on the original financial results. This policy will be reviewed from time to time to ensure that it is compliant with any SEC requirements.

Compensation Governance Practices

The Compensation Committee believes that the Company has strong governance practices in place with respect to executive compensation, as evidenced by the following:

Fully independent Compensation Committee;

Fully independent compensation advisor reporting directly to the Compensation Committee;

Compensation Clawback Policy in the event of a financial restatement;

Executive and Outside Director stock ownership requirements;

Prohibition on hedging and pledging Company stock; and

No perquisites provided to our NEOs.

Executive Compensation Roles and Responsibilities

Compensation Committee

The Compensation Committee establishes the overall compensation philosophy and strategy for the NEOs, determines the Chief Executive Officer's compensation, and reviews and approves compensation levels, plan designs, policies, and practices that it believes are aligned with this philosophy and strategy and that are in the best interests of the Company and its shareholders. Although the Compensation Committee receives input from the Chief Executive Officer (particularly with respect to the other NEOs), executive leadership, and its independent compensation advisor, the Compensation Committee makes its own independent determinations regarding executive compensation.

Chief Executive Officer

The Chief Executive Officer attends portions or all of certain Compensation Committee meetings and makes specific recommendations to the Compensation Committee with respect to each NEO's compensation other than his own. This information is reviewed and considered by the Compensation Committee along with all other relevant factors and circumstances. The Chief Executive Officer is never present when the Compensation Committee meets in executive sessions to discuss the compensation of the NEOs.

Executive Leadership

Various members of executive leadership provide information from time to time either to the Chief Executive Officer or to the Compensation Committee directly. For example, the Chief Financial Officer provides information regarding financial performance and payouts under the short-term incentive program and the General Counsel provides information regarding executive compensation policies and practices such as stock ownership requirements. No members of executive leadership, other than the Chief Executive Officer, generally attend Compensation Committee meetings.

Independent Compensation Advisor

The Compensation Committee has the authority to retain a compensation advisor. Since 2012, the Compensation Committee has annually chosen to retain Pearl Meyer as its compensation advisor. In selecting Pearl Meyer, the Compensation Committee considered the SEC's independence criteria and concluded that Pearl Meyer is independent per the criteria and that the work of Pearl Meyer did not raise any conflicts of interest. Pearl Meyer reports directly to the Compensation Committee, and provides no other services to the Company. Pearl Meyer's services to the Compensation Committee include providing periodic data and information regarding market pay practices and trends, as well as assisting in the development of appropriate compensation program designs and policies, and the preparation of the CD&A. The Compensation Committee has been satisfied with Pearl Meyer's services.

Change of Control Agreements

During 2016, the Company did not have change of control agreements with any of its NEOs.

Richard Stockinger was appointed Chief Executive Officer and President of the Company effective February 28, 2017. On February 24, 2017, the Company entered into an Executive Employment Agreement, which we refer to as the "*Stockinger Employment Agreement*", with Mr. Stockinger and which is further described on page 41 of this Proxy Statement. The Stockinger Employment Agreement provides for certain potential enhanced benefits upon a termination of employment following a change of control of the Company.

The Plan and individual award agreements for awards of restricted stock and performance stock units contain a change of control provision. Under the Plan and individual award agreements for restricted stock, in the event of a change of control of the Company, the vesting provisions on all outstanding unvested restricted shares shall be accelerated and such shares will become fully vested and free of all restrictions. With regard to performance stock units, in the event of a change of control, if the performance stock unit awards (i) are not continued by the Compensation Committee, or not assumed or replaced in an equitable manner to the holder by the successor entity or company after a change in control, then a portion of such performance stock unit award that would have vested as of the scheduled vesting date if the Company were to achieve the target performance level for the performance period shall immediately vest, and (ii) are continued by the Compensation Committee, or are assumed or replaced in an equitable manner to the holder by the successor entity or company after a change of control and if the holder of such performance stock unit award is terminated by the Company for reasons other than cause (as defined under the Plan) or the result of a voluntary termination by the holder, or employment is terminated by the holder for good reason (as defined under the Plan) within one year of the date of the change of control, a portion of such performance stock unit award that would have vested as of the scheduled vesting date if the Company were to achieve the target performance level for the performance period shall immediately vest.

The Role of Benchmarking

The Compensation Committee periodically requests data and information regarding the pay practices and program designs of other, similar companies. However, the Compensation Committee does not benchmark or target a specified pay level or percentile, nor does it follow the practices of similar companies. Instead, the Compensation Committee considers this information along with all other relevant facts and circumstances facing the Company and the executives. Such factors include Company performance, individual executive performance, internal equity, succession planning, affordability, return on investment, accounting expense, tax deductibility and shareholder dilution. During 2016, the Compensation Committee did not request such data and information.

Retirement Benefits

The Company provides and maintains a 401(k) Savings Plan, which we refer to as the "*401(k) Plan*", and a Deferred Compensation Plan, which we refer to as the "*Deferred Compensation Plan*", which are intended to provide the Company's team members with a competitive tax-deferred long-term savings vehicle. The 401(k) Plan is a qualified 401(k) plan and the Deferred Compensation Plan is a non-qualified deferred compensation plan. The NEOs are not eligible to participate in a qualified 401(k) plan once they have been excluded as "highly compensated" employees (as defined under the Code). Under the Deferred Compensation Plan, eligible employees may elect to voluntarily defer portions of their base salary and annual bonus. An eligible employee may elect, with a deferral agreement, to defer all or a specified amount or percentage of base salary and, if applicable, all or a specified amount or percentage of cash bonuses. All amounts deferred by the participants earn interest at 8% per annum. The Company does not provide any matching contributions to the Deferred Compensation Plan.

Executive Perquisites

We did not provide any perquisites to our NEOs in 2016.

Tax Implications

The Compensation Committee has considered the impact of Section 162(m) of the Code. This section disallows a tax deduction for any publicly-held corporation for individual compensation to certain executives of such corporation exceeding $1,000,000 in any taxable year, unless compensation is performance-based. It is the intent of the Company and the Compensation Committee to maximize the deductibility of our executives' compensation whenever possible.

However, the Compensation Committee does not believe that compensation decisions should be based solely upon the amount of compensation that is deductible for federal income tax purposes. Accordingly, the Compensation Committee reserves the right to award compensation that is or could become non-deductible when it believes that such compensation is consistent with our strategic goals and in our best interests.

Report of the Compensation Committee

The Compensation Committee of the Company has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Company's board of directors that the Compensation Discussion and Analysis be included in this Proxy Statement.

Respectfully submitted,

COMPENSATION COMMITTEE

STACEY RAUCH (Chairman)

BRIAN P. FRIEDMAN

JACK A. SMITH

PAUL E. TWOHIG

Compensation Committee Interlocks and Insider Participation

The members of the Compensation Committee for the fiscal year ended January 1, 2017 were Stacey Rauch, Brian P. Friedman, and Jack A. Smith. None of the members of the Compensation Committee were, during such year, an officer of us or any of our subsidiaries or had any relationship with us other than serving as a director. In addition, no executive officer served as a director or a member of the compensation committee of any other entity, other than any subsidiary of ours, one of whose executive officers served as a director or on our Compensation Committee. None of the members of our Compensation Committee had any relationship required to be disclosed under this caption under the rules of the SEC.

Summary Compensation Table

The following table summarizes historical compensation awarded, paid to or earned by the NEOs for the fiscal year ended January 1, 2017, January 3, 2016, and December 28, 2014.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards (1)($)	Option Awards ($)	Non-Equity Incentive Plan Compensation (2)($)	Nonqualified Deferred Compensation Earnings (3)($)	All Other Compensation (4)($)	**Total ($)**
Timothy P. Taft	2016	$454,808 (6)	—	$950,058	—	$—	$ 31,063	—	$1,435,929
Chief Executive Officer	2015	$550,000	—	$950,056	—	$ 99,000	$ 20,197	—	$1,619,253
and President (5)	2014	$525,000	—	$750,006	—	$ 499,800	$ 6,108	—	$1,780,914
Danny K. Meisenheimer	2016	$295,333	—	$275,021	—	$—	$ 6,247	$ 80,709	$657,310
Chief Operating	2015	$288,400	—	$275,122	—	$ 34,608	$ 6,668	—	$604,798
Officer, Pollo Tropical (7)	2014	$280,000	—	$245,018	—	$ 189,512	$ 3,373	—	$717,903
Lynn S. Schweinfurth	2016	$352,000	—	$450,002	—	$—	$ 11,221	—	$813,223
Sr. Vice President,	2015	$352,004	—	$450,129	—	$ 42,240	$ 8,277	—	$852,650
Chief Financial Officer and Treasurer	2014	$320,004	—	$385,002	—	$ 228,480	$ 3,437	—	$936,923
Joseph A. Zirkman	2016	$326,700	—	$225,036	—	$—	$ 8,077	—	$559,813
Sr. Vice President,	2015	$326,700	—	$225,065	—	$ 39,204	$ 5,781		$596,750
General Counsel and Secretary	2014	$297,000	—	$285,013	—	$ 212,058	$ 2,972	$ 85,951	$882,994
John A Todd	2016	$330,000	—	$200,009	—	$ 3,454	$ 310	—	$533,773
Chief Operating Officer,	2015	$330,000	—	$200,101	—	$ 39,600	—	—	$569,701
Pollo Tropical (8)	2014	$300,000	—	$195,023	—	$ 178,500	—	—	$673,523
Joseph W Brink	2016	$200,232	—	$100,040	—	$—	—	—	$300,272
Chief Procurement Officer	2015	$185,400	—	$100,025	—	$ 40,046	—	—	$325,471
	2014	$180,000	—	$155,028	—	$ 85,680	—	—	$420,708

Todd Coerver	2016	$231,805(10)	—	$175,052	—	$—	$ 3,074	—	$409,931
Chief Operating Officer,	2015	$288,400	—	$175,007	—	$ 173,559	$ 2,142	—	$639,108
Taco Cabana(9)	2014	$280,000	—	$150,028	—	$ 178,500	$ 1,818	—	$610,346

(1) These amounts represent the aggregate grant date fair value of restricted stock and performance stock units granted and approved by the Compensation Committee in each of the fiscal years presented and are consistent with the grant date fair value of the award computed in accordance with FASB ASC Topic 718. There were the following forfeitures in 2016: Timothy Taft, 41,002 shares and Todd Coerver, 10,445 shares. There were no other forfeitures by any other NEO in 2016. These amounts reflect the grant date fair value for these awards and do not correspond to the actual value that will be recognized by the NEOs. The actual value, if any, that an NEO may realize will depend on the stock price at the date of vesting. These grants are included and discussed further in the tables below under "Outstanding Equity Awards at Fiscal Year-End". Awards granted in 2016 were comprised of 50% restricted stock and 50% performance stock units. The maximum award payment value (at 200%) for the performance stock units granted in 2016 would be: Mr. Taft - $950,058; Mr. Meisenheimer - $275,021; Ms. Schweinfurth - $450,002; Mr. Zirkman - $225,036; Mr. Todd - $200,009; Mr. Brink - $100,040 and Mr. Coerver - $175,052.

(2) We provide short term cash incentive bonus compensation to our NEOs based on the achievement of certain financial performance goals on a consolidated basis and at the brand level, and an individual's achievement of certain specified objectives. See "Compensation Discussion and Analysis" above for a discussion of our Short Term Incentive Program for the bonus amounts earned in fiscal year 2016. Amounts include any cash bonuses paid in fiscal year 2017, 2016, and 2015 with respect to services rendered in fiscal year 2016, 2015, and 2014, respectively.

(3) These amounts represent the above-market portion of earnings on compensation deferred by the NEOs under our nonqualified Deferred Compensation Plan. Earnings on deferred compensation are considered to be above-market to the extent that the rate of interest exceeds 120% of the applicable federal long-term rate. At January 2, 2017, January 3, 2016, and December 28, 2014, 120% of the federal long-term rate was 3.26%, 3.14%, and 3.24%, per annum, respectively, and the interest rate paid to participants was 8% per annum.

(4) Represents reimbursement of the following moving expenses: Mr. Zirkman's relocation to Dallas, Texas in August of 2014, of which $63,821 represents reimbursable costs and $22,130 represents the "gross-up" on amounts to cover the taxes payable to Mr. Zirkman on such reimbursement and Mr. Meisenheimer's relocation to Dallas, Texas in June 2016, of which $59,599 represents reimbursable costs and $21,110 represents the "gross-up" on amounts to cover the taxes payable to Mr. Meisenheimer on such reimbursement.

(5) Mr. Taft retired as Chief Executive Officer and President of the Company effective September 30, 2016.

(6) Represents total base salary paid to Mr. Taft through September 30, 2016.

(7) Mr. Meisenheimer served as Interim Chief Executive Officer and President of the Company from October 1, 2016 until February 28, 2017 and as Chief Operating Officer, Pollo Tropical until February 28, 2017. Mr. Meisenheimer has served as Senior Vice President and Chief Operating Officer of the Company since February 28, 2017.

(8) Mr. Todd served as Group Vice President, Chief Development Officer until January 1, 2017.

(9) Mr. Coerver resigned as Chief Operating Officer, Taco Cabana effective October 20, 2016.

(10) Represents total base salary paid to Mr. Coerver through October 20, 2016.

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Taft Letter Agreement, Employment Agreement and Agreement

Carrols Restaurant Group, Inc. and Mr. Taft entered into an offer letter, which we refer to as the "*Taft Letter Agreement*", on July 19, 2011, which was assigned to the Company in connection with the spin-off. On February 20, 2014, the Company and Mr. Taft entered into an Executive Employment Agreement, which we refer to as the "*Taft Employment Agreement*", which replaced and superseded the Taft Letter Agreement. The term of the Taft Employment Agreement was from February 20, 2014 until December 31, 2014 and automatically renewed for successive one year terms unless the Taft Employment Agreement was not renewed by Mr. Taft or us or was terminated according to its terms. The Taft Employment Agreement was renewed for 2015 and 2016.

Pursuant to the Taft Employment Agreement, Mr. Taft's base salary was set at $525,000 for 2014, subject to annual increases, as approved by our Compensation Committee. Pursuant to the Taft Employment Agreement, Mr. Taft was eligible to (i) receive a short term incentive bonus, intended to qualify as performance-based compensation under Section 162(m) of the Code, with a target of 80% of Mr. Taft's then base salary based upon attainment of objectives to be established by our Compensation Committee, which the Compensation Committee increased to 90% for 2015, (ii) participate in any long-term incentive bonus plan of ours intended to qualify as performance-based compensation under Section 162(m) of the Code existing from time to time for its executives, and (iii) receive an annual equity grant of $750,000, which the Compensation Committee increased as of 2015 to $950,000.

The Taft Employment Agreement also provided that if Mr. Taft's employment with us was terminated by us in connection with a non-renewal of the Taft Employment Agreement without Cause (as defined in the Taft Employment Agreement) or for reasons other than Cause, death or "permanent and total disability" (within the meaning of Section 22(e)(3) of the Code) or was voluntarily terminated by Mr. Taft for Good Reason (as defined in the Taft Employment Agreement), he was entitled to receive (i) one year of his then base salary, (ii) a pro rata portion of any annual cash bonus that Mr. Taft would have been entitled to receive with respect to the fiscal year of termination had his employment not been terminated, (iii) the payment by us of premium payments for a period of up to twelve months if Mr. Taft and his dependents elect coverage under our health insurance plan pursuant to the Consolidated Omnibus Budget Reconciliation Act, and (iv) executive outplacement services in an amount not to exceed $25,000 to be incurred no later than the end of the second year following the year of termination.

If Mr. Taft's employment with us was terminated by us for Cause or if his employment with us ended due to death, permanent and total disability or due to a voluntary non-renewal of the Taft Employment Agreement or voluntary termination of employment by Mr. Taft without Good Reason, he was entitled to receive any earned but unpaid compensation as well as any other amounts or benefits owing to Mr. Taft under the terms of any employee benefit plan of ours.

Mr. Taft, pursuant to the Taft Employment Agreement, agreed, for a period of one year following his termination of employment with us, not to directly or indirectly solicit for employment or employ any person who is or was employed by us within six months prior to his termination date.

Additionally, under the Taft Employment Agreement, Mr. Taft agreed for a period of one year following his termination of employment with us, not to be employed by, or associated with, as an employee, consultant, director or in any other capacity, any company operating Tex-Mex or Mexican-themed quick service, quick casual or casual dining restaurants which competes with our Taco Cabana concept, or any company operating Hispanic-themed quick-service, quick-casual, fast-casual or casual dining restaurants which feature grilled chicken as the primary or central menu item and also competes with our Pollo Tropical concept.

In connection with Mr. Taft's retirement as our Chief Executive Officer and President effective September 30, 2016, on September 27, 2016, we and Mr. Taft entered into an agreement, which we refer to as the "*Taft Agreement*", whereby we agreed to accelerate the time based vesting of 21,898 restricted shares of our Common Stock previously issued to Mr. Taft under our Plan. Pursuant to the Taft Agreement, Mr. Taft agreed to extend the period of his covenant to not compete under the Taft Employment Agreement dated as of February 20, 2014 to two years from one year.

Schweinfurth Letter Agreement and Schweinfurth Agreement

Pursuant to the terms of an offer letter between Fiesta Restaurant Group and Ms. Schweinfurth entered into on June 29, 2012, which we refer to as the "*Schweinfurth Letter Agreement*", Ms. Schweinfurth earned an annual base salary of $320,000 beginning in 2012 and became eligible for annual merit increases beginning in 2014 based upon recommendations of our Chief Executive Officer and Compensation Committee. The Schweinfurth Letter Agreement also provided that Ms. Schweinfurth would participate in the executive bonus program, as established by our Compensation Committee.

Pursuant to the Schweinfurth Letter Agreement, within 30 days of July 16, 2012, the date of Ms. Schweinfurth's commencement of employment with the Company, Ms. Schweinfurth received a one-time sign on grant of 50,000 shares of restricted common stock of the Company in connection with her appointment as our Vice President, Chief Financial Officer and Treasurer. The restricted shares of the Company's common stock granted to Ms. Schweinfurth vested over four years at the rate of 25% per annum beginning on the first anniversary of the date of grant and are subject to provisions of the Plan.

The Schweinfurth Letter Agreement also provided that in the event Ms. Schweinfurth is terminated without Cause (as defined in the Schweinfurth Letter Agreement), she was entitled to receive a severance payment equal to her twelve months base salary and the pro-rated portion of her bonus payable, provided that a bonus would have been payable.

On November 4, 2016, the Company and Ms. Schweinfurth entered into the Schweinfurth Agreement pursuant to which Ms. Schweinfurth is entitled to a retention bonus payment of (a) $150,000, which we refer to as the "*Schweinfurth 2016 Bonus*", which was paid in February 2017; provided that if Ms. Schweinfurth (i) voluntarily resigns as an employee of the Company other than for Good Reason (as defined in the Schweinfurth Agreement) or gives notice of such resignation any time during the twelve month period following the payment date of the Schweinfurth 2016 Bonus or (ii) if Ms. Schweinfurth voluntarily resigns as an employee of the Company other than for Good Reason any time prior to December 31, 2017 and fails to provide at least six months prior written notice of such voluntary resignation, Ms. Schweinfurth shall repay the Schweinfurth 2016 Bonus to the Company, and (b) $150,000 less any amount related to short term incentive compensation received by Ms. Schweinfurth under the Company's Executive Bonus Plan (as defined in the Schweinfurth Agreement), which we refer to as the "*Schweinfurth 2017 Bonus*", payable in February 2018, provided that Ms. Schweinfurth remains employed with the Company through the payment date of the Schweinfurth 2017 Bonus. The Schweinfurth Agreement also modifies and supersedes the severance bonus arrangements contained in the Schweinfurth Letter Agreement, and provides that upon a termination of Ms. Schweinfurth's employment by the Company without Cause (as defined in the Schweinfurth Agreement) or termination of Ms. Schweinfurth's employment by Ms. Schweinfurth with Good Reason, Ms. Schweinfurth is entitled to (i) an amount equal to one times Ms. Schweinfurt's highest annual base salary in effect prior to the date Ms. Schweinfurth's employment is terminated and (ii) an amount equal to a pro rata portion of the aggregate bonus under the Company's Executive Bonus Plan for the year in which Ms. Schweinfurth's employment is terminated (plus any earned and unpaid bonus amounts under the Company's Executive Bonus Plan for the year prior to the year in which Ms. Schweinfurth's employment is terminated). The Schweinfurth Agreement terminates (other than the severance bonus provisions which shall survive any such termination, consistent with the terms of the Schweinfurth Letter Agreement) on December 31, 2018 and if renewed by the Company upon 90 days written notice prior to the expiration of the initial term, on December 31, 2019, unless terminated sooner in accordance with the terms of the Schweinfurth Agreement.

Zirkman Agreement

On November 4, 2016, the Company and Mr. Zirkman entered into the Zirkman Agreement pursuant to which Mr. Zirkman is entitled to a retention bonus payment of (a) $100,000, which we refer to as the "*Zirkman 2016 Bonus*", which was paid in February 2017; provided that if Mr. Zirkman (i) voluntarily resigns as an employee of the Company other than for Good Reason (as defined in the Zirkman Agreement) or gives notice of such resignation any time during the twelve month period following the payment date of the Zirkman 2016 Bonus or (ii) if Mr. Zirkman voluntarily resigns as an employee of the Company other than for Good Reason any time prior to December 31, 2017 and fails to provide at least six months prior written notice of such voluntary resignation, Mr. Zirkman shall repay the Zirkman 2016 Bonus to the Company, and (b) $100,000 less any amount related to short term incentive compensation received by Mr. Zirkman under the Company's Executive Bonus Plan (as defined in the Zirkman Agreement), which we refer to as the "*Zirkman 2017 Bonus*", payable in February 2018, provided that Mr. Zirkman remains employed with

the Company through the payment date of the Zirkman 2017 Bonus. The Zirkman Agreement also provides that upon a termination of Mr. Zirkman's employment by the Company without Cause (as defined in the Zirkman Agreement) or termination of Mr. Zirkman's employment by Mr. Zirkman with Good Reason, Mr. Zirkman is entitled to (i) an amount equal to one times Mr. Zirkman 's highest annual base salary in effect prior to the date Mr. Zirkman's employment is terminated and (ii) an amount equal to a pro rata portion of the aggregate bonus under the Company's Executive Bonus Plan (as defined in the Zirkman Agreement) for the year in which Mr. Zirkman's employment is terminated (plus any earned and unpaid bonus amounts under the Company's Executive Bonus Plan for the year prior to the year in which Mr. Zirkman's employment is terminated). The Zirkman Agreement terminates on December 31, 2018 and if renewed by the Company upon 90 days written notice prior to the expiration of the initial term, on December 31, 2019, unless terminated sooner in accordance with the terms of the Zirkman Agreement.

Meisenheimer Agreement

On November 4, 2016, the Company and Mr. Meisenheimer entered into the Meisenheimer Agreement pursuant to which Mr. Meisenheimer is entitled to a retention bonus payment of (a) $175,000, which we refer to as the "*Meisenheimer 2016 Bonus*", which was paid in February 2017; provided that if Mr. Meisenheimer (i) voluntarily resigns as an employee of the Company other than for Good Reason (as defined in the Meisenheimer Agreement) or gives notice of such resignation any time during the twelve month period following the payment date of the Meisenheimer 2016 Bonus or (ii) if Mr. Meisenheimer voluntarily resigns as an employee of the Company other than for Good Reason any time prior to December 31, 2017 and fails to provide at least six months prior written notice of such voluntary resignation, Mr. Meisenheimer shall repay the Meisenheimer 2016 Bonus to the Company, and (b) $175,000 less any amount related to short term incentive compensation received by Mr. Meisenheimer under the Company's Executive Bonus Plan (as defined in the Meisenheimer Agreement), which we refer to as the "*Meisenheimer 2017 Bonus*", payable in February 2018, provided that Mr. Meisenheimer remains employed with the Company through the payment date of the Meisenheimer 2017 Bonus. The Meisenheimer Agreement also provides that upon a termination of Mr. Meisenheimer's employment by the Company without Cause (as defined in the Meisenheimer Agreement), termination of Mr. Meisenheimer's employment by Mr. Meisenheimer with Good Reason (other than in the case of a material diminution of Mr. Meisenheimer's authority, duties or responsibilities) and termination of Mr. Meisenheimer's employment by Mr. Meisenheimer for any reason during the period that is between six months and twelve months following the commencement date of employment of a new Chief Executive Officer of the Company, Mr. Meisenheimer is entitled to (i) an amount equal to two times Mr. Meisenheimer' s highest annual base salary in effect prior to the date Mr. Meisenheimer's employment is terminated and (ii) an amount equal to a pro rata portion of the aggregate bonus under the Company's Executive Bonus Plan (as defined in the Meisenheimer Agreement) for the year in which Mr. Meisenheimer's employment is terminated (plus earned and unpaid bonus amounts under the Company's Executive Bonus Plan for the year prior to the year in which Mr. Meisenheimer's employment is terminated). The Meisenheimer Agreement terminates on December 31, 2018 and if renewed by the Company upon 90 days written notice prior to the expiration of the initial term, on December 31, 2019 unless terminated sooner in accordance with the terms of the Meisenheimer Agreement.

Brink Agreement

On November 9, 2016, the Company and Mr. Brink entered into the Brink Agreement pursuant to which Mr. Brink is entitled to a retention bonus payment of (a) $40,000, which we refer to as the "*Brink 2016 Bonus*", which was paid in February 2017; provided that if Mr. Brink (i) voluntarily resigns as an employee of the Company, gives notice of such resignation or is terminated for Cause (as defined in the Brink Agreement) any time during the twelve month period following the payment date of the Brink 2016 Bonus, Mr. Brink shall repay the Brink 2016 Bonus to the Company, and (b) $40,000 less any amount related to short term incentive compensation received by Mr. Brink under the Company's Employee Bonus Plan (as defined in the Brink Agreement), which we refer to as the "*Brink 2017 Bonus*", payable in February 2018, provided that Mr. Brink remains employed with the Company through the payment date of the Brink 2017 Bonus.

Stockinger Employment Agreement

Mr. Stockinger was appointed Chief Executive Officer and President of the Company effective February 28, 2017. On February 24, 2017, the Company entered into the Stockinger Employment Agreement pursuant to which Mr. Stockinger will earn a base salary of $550,000 per year which can be increased at the sole discretion of the Compensation Committee. Pursuant to the Stockinger Employment Agreement, Mr. Stockinger will (i) be eligible to receive a short term cash incentive bonus equal to at least 100% of Mr. Stockinger's then base salary based upon attainment of objectives to be established by the Compensation Committee, (ii) receive a grant of restricted common stock of the Company on March 6, 2017 pursuant to the Plan with a value of $3,000,000 (based on the closing price of the Company's common stock on such date) which will consist of 50% time-based restricted stock of the Company vesting 25% on each anniversary date over four years and 50% performance-based restricted stock units of the Company vesting 25% on each anniversary date over four years if the performance conditions and metrics, which are to be determined by the Compensation Committee, are achieved, and (iii) commencing with our 2021 fiscal year (or such earlier time as may be determined by the Compensation Committee in its sole discretion), will be entitled to receive additional annual long-term incentive awards as may be determined by the Compensation Committee.

The Stockinger Employment Agreement provides that if Mr. Stockinger's employment with the Company is terminated by the Company for Cause (as defined in the Stockinger Employment Agreement) or if his employment with the Company ends due to death or "permanent and total disability" (within the meaning of Section 22(e)(3) of the Code) or voluntary termination of employment by Mr. Stockinger without Good Reason (as defined in the Stockinger Employment Agreement), he shall be entitled to receive (i) any earned but unpaid compensation, (ii) solely with respect to Mr. Stockinger's termination for death or "permanent and total disability", any earned but unpaid bonus for any completed year prior to the date of termination and (iii) any other amounts or benefits owing to Mr. Stockinger under the terms of any employee benefit plan of the Company or, in the case of equity-based compensation awards, under the terms of the equity award plan or applicable award agreement, which we refer to as the "*Accrued Benefits*".

The Stockinger Employment Agreement also provides that if Mr. Stockinger's employment with the Company is terminated by the Company without Cause or for reasons other than death or "permanent and total disability" or is voluntarily terminated by Mr. Stockinger for Good Reason, he shall be entitled to receive (i) 1.5 times his then base salary, to be paid at least monthly, (ii) any earned but unpaid bonus for any completed year prior to the date of termination plus a pro rata portion of any annual bonus that Mr. Stockinger would have been entitled to receive with respect to the fiscal year of termination had his employment not been terminated, (iii) the payment by the Company of premium payments for a period of up to twelve months if Mr. Stockinger and his dependents elect coverage under the Company's health insurance plan pursuant to the Consolidated Omnibus Budget Reconciliation Act, which we refer to as "*COBRA*", (iv) executive outplacement services in an amount not to exceed $25,000 to be incurred no later than the end of the second year following the year of termination and (v) the Accrued Benefits.

If within one year after the occurrence of a Change of Control (as defined in the Stockinger Employment Agreement), Mr. Stockinger's employment with the Company is terminated by the Company without Cause and for reasons other than death or "permanent and total disability" or is voluntarily terminated by Mr. Stockinger for Good Reason, then Mr. Stockinger shall be entitled to (i) 2.0 times his then base salary, payable in a lump sum (ii) any earned but unpaid bonus for any completed year prior to the date of termination plus a pro rata portion of any annual bonus that Mr. Stockinger would have been entitled to receive with respect to the fiscal year of termination had his employment not been terminated, (iii) the acceleration of the vesting provisions of Mr. Stockinger's outstanding unvested time-based restricted stock awards, (iv) the acceleration of the vesting provisions of a portion of Mr. Stockinger's outstanding performance-based restricted stock unit awards that would have vested as of the scheduled vesting date if the Company were to have achieved the target performance level for the performance period, if (x) such awards are not continued by the Committee or not assumed or replaced in an equitable manner by the successor entity after a Change of Control or (y) such awards are continued by the Committee, or are assumed or replaced in an equitable manner by the successor entity after a Change of Control and, within one year after the date of Change of Control, Mr. Stockinger's employment is terminated without Cause and for reasons other than death or "permanent disability" or voluntarily terminated by Mr. Stockinger for Good Reason, (v) the payment by the Company of premium payments for a period of up to twelve months if Mr. Stockinger and his dependents elect coverage under the Company's health insurance plan pursuant to COBRA, (vi) executive outplacement services in an amount not to exceed $25,000 to be incurred no later than the end of the second year following the year of termination and (vii) the Accrued Benefits.

Mr. Stockinger, pursuant to the Stockinger Employment Agreement, agreed, for a period of two years following his termination of employment with the Company, not to directly or indirectly solicit for employment or employ any person who is or was employed by the Company within six months prior to his termination date.

Additionally, under the Stockinger Employment Agreement, Mr. Stockinger agreed for a period of eighteen months following his termination of employment with the Company, not to be employed by or associated with as employee, consultant, director, or in any other equivalent capacity, any company operating Tex−Mex or Mexican−themed quick-service, quick-casual, fast-casual or casual dining restaurants, or any company operating Caribbean or Hispanic−themed quick-service, quick-casual, fast-casual or casual dining restaurants which feature grilled chicken as the primary or central menu item.

Grants of Plan-Based Rewards

The following table provides certain historical information regarding grants of plan-based awards made to the NEOs during the fiscal year ended January 1, 2017:

	Grant	Approval	Estimated Payouts Under Non-Equity Incentive Plan	Estimated Future Payouts Under Equity Incentive Plan Awards(#)			All Other Stock Awards: Number of Shares or Units	Grant Date Fair Value of Stock
Name	Date	Date (1)	Awards	Threshold	Target (2)	Maximum	(#)(3)	Awards (4)
Timothy P. Taft	3/2/2016	2/16/2016	$ -	6,738	13,476	26,952	13,476	$ 950,058
Danny K. Meisenheimer	3/2/2016	2/16/2016	$ -	1,951	3,901	7,802	3,901	$ 275,021
Lynn S. Schweinfurth	3/2/2016	2/16/2016	$ -	3,192	6,383	12,766	6,383	$ 450,002
Joseph A. Zirkman	3/2/2016	2/16/2016	$ -	1,596	3,192	6,384	3,192	$ 225,036
John A Todd	3/2/2016	2/16/2016	$ -	1,419	2,837	5,674	2,837	$ 200,009
Joseph W Brink	3/2/2016	2/16/2016	$ -	710	1,419	2,838	1,419	$ 100,040
Todd Coerver	3/2/2016	2/16/2016	$ -	1,242	2,483	4,966	2,483	$ 175,052

(1) The grants of plan-based awards in this table above were approved by our Compensation Committee on February 16, 2016.

(2) Amounts shown in this column reflect the target number of performance stock units granted to each NEO pursuant to the Plan during 2016. Vesting of the 2016 performance award on March 2, 2019 is based on cumulative achievement of predetermined performance metrics in each of three consecutive fiscal years that comprise the performance period for which the award is made.

(3) Amounts shown in this column reflect the number of restricted stock awards granted to each NEO pursuant to the Plan during 2016. The 2016 restricted stock vests 25% on each anniversary date over four years, however, in each year, awards vest only if we achieve at least 75% of budgeted EBT. If we fail to achieve at least 75% of budgeted EBT, the shares of restricted stock for that vesting period are forfeited by each NEO. The Company did not achieve over 75% of its EBT target for 2016 and, accordingly, the first 25% of the 2016 and the second 25% of the 2015 restricted stock awards to the NEOs did not vest and were forfeited. The following restricted stock awards were forfeited by the NEOs in February and March 2017: Mr. Meisenheimer – 1,505 shares, Ms. Schweinfurth – 2,462 shares, Mr. Zirkman – 1,231 shares, Mr. Todd 1,095 shares and Mr. Brink – 355 shares.

(4) The value of the restricted stock and performance stock units granted in 2016 is calculated by multiplying the number of shares of restricted stock awarded and the target number of performance stock units granted by the market closing price of our common stock on the grant date. The grant date fair value for the March 2, 2016 grant was $35.25 per share.

2012 Stock Incentive Plan. The Plan provides for the grant of stock options and stock appreciation rights, stock awards, performance awards, outside director stock options, and outside director stock awards. Any officer, employee, associate, director and any consultant or advisor providing services to us are eligible to participate in the Plan.

The Plan is administered by the Compensation Committee which approves awards and may base its considerations on recommendations by our Chief Executive Officer. The Compensation Committee has the authority to (1) approve plan participants, (2) approve whether and to what extent stock options, stock appreciation rights, stock awards, and performance awards are to be granted and the number of shares of stock to be covered by each award (other than an outside director award), (3) approve forms of agreement for use under the Plan, (4) determine terms and conditions of awards (including, but not limited to, the option price, any vesting restriction or limitation, any vesting acceleration or waiver or forfeiture, and any right of repurchase, right of first refusal or other transfer restriction regarding any award), (5) modify, amend or adjust the terms and conditions of any award, (6) determine the fair market value, and (7) determine the type and amount of consideration to be received by us for any stock award issued.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to the value of all equity awards that were not vested at the January 1, 2017 fiscal year end for each of the NEOs.

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(2)	Equity Incentive Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Timothy P. Taft (1)	—	—	—	—	—	—	—	—	—
Danny K. Meisenheimer	—	—	—	—	—	1,459(3)	$43,551	—	—
	—	—	—	—	—	1,665(4)	$49,700	—	—
	—	—	—	—	—	2,109(7)	$62,954	—	—
	—	—	—	—	—	1,587(5)	$47,372	—	—
	—	—	—	—	—	3,901(9)	$116,445	—	—
	—	—	—	—	—	—	—	2,116 (6)	$63,163
	—	—	—	—	—	—	—	3,901 (8)	$116,445
Lynn S. Schweinfurth	—	—	—	—	—	3,042(3)	$90,804	—	—
	—	—	—	—	—	2,775(4)	$82,834	—	—
	—	—	—	—	—	2,997(7)	$89,460	—	—
	—	—	—	—	—	2,596(5)	$77,491	—	—
	—	—	—	—	—	6,383(9)	$190,533	—	—
	—	—	—	—	—	—	—	3,462 (6)	$103,341
	—	—	—	—	—	—	—	6,383 (8)	$190,533
Joseph A. Zirkman	—	—	—	—	—	1,825(3)	$54,476	—	—
	—	—	—	—	—	1,665(4)	$49,700	—	—
	—	—	—	—	—	2,997(7)	$89,460	—	—
	—	—	—	—	—	1,298(5)	$38,745	—	—
	—	—	—	—	—	3,192(9)	$95,281	—	—

	—	—	—	—	—	—	—	1,731 (6)	$51,670
	—	—	—	—	—	—	—	3,192 (8)	$95,281
John A. Todd	—	—	—	—	—	1,154(5)	$34,447	—	—
	—	—	—	—	—	2,837(9)	$84,684	—	—
	—	—	—	—	—	—	—	1,539 (6)	$45,939
	—	—	—	—	—	—	—	2,837 (8)	$84,684
Joseph W. Brink	—	—	—	—	—	607 (3)	$18,119	—	—
	—	—	—	—	—	1,109(4)	$33,104	—	—
	—	—	—	—	—	1,221(7)	$36,447	—	—
	—	—	—	—	—	1,419(9)	$42,357	—	—
	—	—	—	—	—	1,209(10)	$36,089	—	—
	—	—	—	—	—	—	—	1,419 (8)	$42,357
Todd Coerver(11)	—	—	—	—	—	—	—	—	—

(1) In connection with Mr. Taft's retirement as our Chief Executive Officer and President effective September 30, 2016, on September 27, 2016, pursuant to the Taft Agreement, we agreed to accelerate the time based vesting of 21,898 restricted shares of our Common Stock previously issued to Mr. Taft under our Plan; provided that Mr. Taft remained an employee of the Company or continued to provide services to us through September 30, 2016. All other unvested restricted shares of Common Stock held by Mr. Taft were forfeited to the Company.

(2) The market value of the restricted stock awards was determined based on the closing price of our common stock on the last trading day of the fiscal year, December 30, 2016, which was $29.85.

(3) Represents restricted shares of Common Stock that vest 100% on February 14, 2017.

(4) Represents restricted shares of Common Stock that vest 50% on each of February 19, 2017 and February 19, 2018.

(5) Represents restricted shares of Common Stock that vest in increments of one-third on each of February 27, 2017, February 27, 2018 and February 27, 2019, each subject to the achievement of certain performance criteria. This performance criteria requires the Company to achieve 75% of its EBT target each year in order for the restricted stock to vest at the time the service condition is sae:11pt;">)

Income Before Income Tax Expense and Equity Earnings	94.5	81.7	351.7	240.1
Income Tax Expense	38.6	35.2	142.1	103.2
Equity Earnings of Unconsolidated Subsidiaries	20.6	23.0	68.7	72.6
Net Income	76.5	69.5	278.3	209.5
Net Income Attributable to Noncontrolling Interests	1.0	0.5	2.6	2.0
Earnings Attributable to AEP Common Shareholders	$ 75.5	$69.0	$275.7	$207.5

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30,	
	2017	2016
	(in millions)	
Plant in Service	$5,001.4	$3,330.5
CWIP	1,392.8	1,565.8
Accumulated Depreciation	156.6	88.1
Total Transmission Property, Net	$6,237.6	$4,808.2

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Third Quarter of 2017 Compared to Third Quarter of 2016

Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2016	$69.0
Changes in Transmission Revenues:	
Transmission Revenues	46.1
Total Change in Transmission Revenues	46.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.9)
Depreciation and Amortization	(9.0)
Taxes Other Than Income Taxes	(5.9)
Interest and Investment Income	0.1
Allowance for Equity Funds Used During Construction	(1.9)
Interest Expense	(5.7)
Total Change in Expenses and Other	(33.3)
Income Tax Expense	(3.4)
Equity Earnings	(2.4)
Net Income Attributable to Noncontrolling Interests	(0.5)
Third Quarter of 2017	$75.5

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

- Transmission Revenues increased $46 million primarily due to an increase in formula rates driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $9 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $6 million primarily due to increased property taxes as a result of additional transmission investment.
- Interest Expense increased $6 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2016	$207.5
Changes in Transmission Revenues:	
Transmission Revenues	199.2
Total Change in Transmission Revenues	199.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(21.8)
Depreciation and Amortization	(26.3)
Taxes Other Than Income Taxes	(19.3)
Interest and Investment Income	0.5
Carrying Costs Expense	0.1
Allowance for Equity Funds Used During Construction	(3.9)
Interest Expense	(16.9)
Total Change in Expenses and Other	(87.6)
Income Tax Expense	(38.9)
Equity Earnings	(3.9)
Net Income Attributable to Noncontrolling Interests	(0.6)
Nine Months Ended September 30, 2017	$275.7

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 $199 million primarily due to the current year favorable impact of the modification of the PJM OATT formula rates combined with an increase driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $22 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $26 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $19 million primarily due to increased property taxes as a result of additional transmission investment.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to the FERC transmission complaint and an increase in the amount of short-term debt, offset by an increase in the CWIP balance.
- Interest Expense increased $17 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $39 million primarily due to an increase in pretax book income.
- Equity Earnings decreased $4 million primarily due to lower earnings at ETT resulting from increased property taxes, depreciation expense, and decreased AFUDC, partially offset by increased revenues. The revenue increase is primarily due to interim rate increases in the third quarter of 2016 and higher loads, partially offset by an ETT rate reduction that went into effect in March 2017.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Revenues	$465.5	$859.4	$1,467.5	$2,291.2
Fuel, Purchased Electricity and Other	354.6	567.4	1,062.7	1,490.6
Gross Margin	110.9	292.0	404.8	800.6
Other Operation and Maintenance	56.5	95.8	211.4	290.2
Asset Impairments and Other Related Charges	(2.5)	2,254.4	10.6	2,254.4
Gain on Sale of Merchant Generation Assets	—	—	(226.4)	—
Depreciation and Amortization	6.2	50.5	17.5	149.8
Taxes Other Than Income Taxes	3.2	8.7	8.9	29.0
Operating Income (Loss)	47.5	(2,117.4)	382.8	(1,922.8)
Interest and Investment Income	2.7	0.3	7.9	1.2
Interest Expense	(4.0)	(9.5)	(14.7)	(27.1)
Income (Loss) Before Income Tax Expense	46.2	(2,126.6)	376.0	(1,948.7)
Income Tax Expense (Credit)	12.5	(757.4)	129.7	(699.9)
Net Income (Loss)	33.7	(1,369.2)	246.3	(1,248.8)
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$33.7	$(1,369.2)	$246.3	$(1,248.8)

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions of MWhs)			
Fuel Type:				
Coal	2	8	10	19
Natural Gas	—	4	2	11
Total MWhs	2	12	12	30

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Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2016	$(1,369.2)
Changes in Gross Margin:	
Generation	(175.4)
Retail, Trading and Marketing	(10.1)
Other	4.4
Total Change in Gross Margin	(181.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	39.3
Asset Impairments and Other Related Charges	2,256.9
Depreciation and Amortization	44.3
Taxes Other Than Income Taxes	5.5
Interest and Investment Income	2.4
Interest Expense	5.5
Total Change in Expenses and Other	2,353.9
Income Tax Expense	(769.9)
Third Quarter of 2017	$33.7

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

- Generation decreased $175 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- Retail, Trading and Marketing decreased $10 million due to lower retail margins in 2017 partially offset by favorable wholesale trading and marketing performance in 2017.
- Other increased $4 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $39 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- Asset Impairments and Other Related Charges decreased $2.3 billion due to the asset impairment of certain merchant generation assets in 2016.
- Depreciation and Amortization expenses decreased $44 million primarily due to the sale and impairment of certain merchant generation assets.
- Taxes Other Than Income Taxes decreased $6 million primarily due to the sale of certain merchant generation assets.
- Interest Expense decreased $6 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.

- Income Tax Expense increased $770 million primarily due to an increase in pretax book income resulting primarily from the impairment of certain merchant generation assets in 2016.

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Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016
Reconciliation of Nine Months Ended September 30, 2016
to Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

Nine Months Ended September 30, 2016	$(1,248.8)
Changes in Gross Margin:	
Generation	(376.2)
Retail, Trading and Marketing	(33.6)
Other	14.0
Total Change in Gross Margin	(395.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	78.8
Asset Impairments and Other Related Charges	2,243.8
Gain on Sale of Merchant Generation Assets	226.4
Depreciation and Amortization	132.3
Taxes Other Than Income Taxes	20.1
Interest and Investment Income	6.7
Interest Expense	12.4
Total Change in Expenses and Other	2,720.5
Income Tax Expense	(829.6)
Nine Months Ended September 30, 2017	$246.3

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

- Generation decreased $376 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- Retail, Trading and Marketing decreased $34 million primarily due to lower margins in 2017 combined with the impact of favorable wholesale trading and marketing performance in 2016.
- Other increased $14 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $79 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- Asset Impairments and Other Related Charges decreased $2.2 billion due to the asset impairment of certain merchant generation assets in 2016.
- Gain on Sale of Merchant Generation Assets increased $226 million due to the sale of certain merchant generation assets.
- Depreciation and Amortization expenses decreased $132 million primarily due to the sale and impairment of certain merchant generation assets.

- Taxes Other Than Income Taxes decreased $20 million primarily due to the sale of certain merchant generation assets.
- Interest and Investment Income increased $7 million primarily due to increased cash invested as a result of the sale of certain merchant generation assets.
- Interest Expense decreased $12 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.
- Income Tax Expense increased $830 million primarily due to an increase in pretax book income and state income taxes resulting primarily from the impairment of certain merchant generation assets in 2016.

CORPORATE AND OTHER

Third Quarter of 2017 Compared to Third Quarter of 2016

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $36 million in 2016 to $5 million in 2017 primarily due to the prior year reversal of a capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as tax return adjustments related to the prior year disposition of AEP's commercial barging operations, partially offset by the gain recognized on the sale of a cost-based investment in the third quarter of 2017.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from income of $62 million in 2016 to a loss of $11 million in 2017 primarily due to the prior year reversal of capital loss valuation allowances related to effectively settling a 2011 audit issue with the IRS and the impact of the pending sale of certain merchant generation assets as well as 2015 tax return adjustments related to the disposition of AEP's commercial barging operations, partially offset by the gain recognized on the sale of a cost-based investment in the third quarter of 2017.

AEP SYSTEM INCOME TAXES

Third Quarter of 2017 Compared to Third Quarter of 2016

Income Tax Expense increased $799 million primarily due to an increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in Income Tax Expense is also due to the third quarter of 2016 reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Income Tax Expense increased $932 million primarily due to an increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in Income Tax Expense is also due to the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS, the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2017			December 31, 2016			
	(dollars in millions)						
Long-term Debt, including amounts due within one year	$20,721.7	51.9	%	$20,391.2	(a)	51.6	%
Short-term Debt	1,059.3	2.7		1,713.0		4.3	
Total Debt	21,781.0	54.6		22,104.2	(a)	55.9	
AEP Common Equity	18,069.1	45.3		17,397.0		44.0	
Noncontrolling Interests	36.4	0.1		23.1		0.1	
Total Debt and Equity Capitalization	$39,886.5	100.0	%	$39,524.3		100.0	%

(a) 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 6 for additional information.

AEP’s ratio of debt-to-total capital decreased from 55.9% as of December 31, 2016 to 54.6% as of September 30, 2017 primarily due to a decrease in short-term debt due to the use of proceeds from the sale of Merchant Generation Assets to pay down debt. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP’s financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of September 30, 2017, AEP had a $3 billion revolving credit facility commitment to support its operations. In May 2017, the $500 million revolving credit facility due in June 2018 was terminated. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2017, available liquidity was approximately $3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$3,000.0	June 2021
Total	3,000.0	
Cash and Cash Equivalents	343.9	
Total Liquidity Sources	3,343.9	
Less: AEP Commercial Paper Outstanding	295.0	

Net Available Liquidity	$ 3,048.9

AEP has a $3 billion revolving credit facility to support its commercial paper program.

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AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first nine months of 2017 was $1.6 billion. The weighted-average interest rate for AEP's commercial paper during 2017 was 1.19%.

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 five uncommitted facilities totaling $445 million. In August 2017, AEP executed a $75 million uncommitted letter of credit facility due in August 2018. As of September 30, 2017, the maximum future payment for letters of credit issued under the uncommitted facilities was $123 million with maturities ranging from October 2017 to September 2018.

Securitized Accounts Receivable

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2019.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of September 30, 2017, this contractually-defined percentage was 52.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facility does not permit the lenders to refuse a draw on the facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.62 per share in October 2017. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

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

Credit Ratings

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

CASH FLOW

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

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$210.5	$176.4
Net Cash Flows from Continuing Operating Activities	3,124.2	3,421.0
Net Cash Flows Used for Continuing Investing Activities	(1,676.6)	(3,428.7)
Net Cash Flows from (Used for) Continuing Financing Activities	(1,314.2)	46.0
Net Cash Flows Used for Discontinued Operations	—	(2.5)
Net Increase in Cash and Cash Equivalents	133.4	35.8
Cash and Cash Equivalents at End of Period	$343.9	$212.2

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

Operating Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Income from Continuing Operations	$1,527.1	$245.3
Depreciation and Amortization	1,485.9	1,550.2
Deferred Income Taxes	740.9	(47.0)
Asset Impairments and Other Related Charges	10.6	2,264.9
Gain on Sale of Merchant Generation Assets	(226.4)	—
Provision for Refund – Global Settlement, Net	(93.3)	—
Accrued Taxes, Net	(310.1)	(393.0)
Other	(10.5)	(199.4)
Net Cash Flows from Continuing Operating Activities	$3,124.2	$3,421.0

Net Cash Flows from Continuing Operating Activities were $3.1 billion in 2017 consisting primarily of Income from Continuing Operations of $1.5 billion and $1.5 billion of noncash Depreciation and Amortization. In addition, AEP recorded a gain of $226 million on the sale of certain merchant generation assets. AEP also recorded asset impairments of $11 million. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a

complete discussion of this sale and these impairments. Deferred and Accrued Taxes changed primarily due to the income tax impacts associated with the sale of certain merchant generation assets and the receipt of a tax refund related to the U.K. Windfall Tax. AEP refunded $93 million to customers as part of the Ohio Global Settlement reached in 2016. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities.

Net Cash Flows from Continuing Operating Activities were $3.4 billion in 2016 consisting primarily of Income from Continuing Operations of $245 million and $1.6 billion of noncash Depreciation and Amortization. AEP also had asset impairments of $2.3 billion during the third quarter of 2016. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale and Impairments for a complete discussion of asset impairments and other related charges. Accrued Taxes decreased primarily due to the impacts of bonus depreciation related to the Protecting Americans from Tax Hikes Act of 2015. Deferred Income Taxes decreased primarily due to the tax effect of the asset impairment partially offset by an increase in tax versus book temporary differences from operations, which includes provisions related to the Protecting Americans from Tax Hikes Act of 2015. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities.

Investing Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Construction Expenditures	$(3,778.2)	$(3,387.0)
Acquisitions of Nuclear Fuel	(73.2)	(127.6)
Proceeds from Sale of Merchant Generation Assets	2,159.6	—
Other	15.2	85.9
Net Cash Flows Used for Continuing Investing Activities	$(1,676.6)	$(3,428.7)

Net Cash Flows Used for Continuing Investing Activities were $1.7 billion in 2017 primarily due to Construction Expenditures for environmental, distribution and transmission investments, partially offset by the proceeds received from the sale of certain merchant generation assets. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale.

Net Cash Flows Used for Continuing Investing Activities were $3.4 billion in 2016 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Issuance of Common Stock, Net	$—	$34.2
Issuance/Retirement of Debt, Net	(338.2)	930.3
Make Whole Premium on Extinguishment of Long-term Debt	(46.1)	—
Dividends Paid on Common Stock	(875.0)	(829.8)
Other	(54.9)	(88.7)
Net Cash Flows from (Used for) Continuing Financing Activities	$(1,314.2)	$46.0

Net Cash Flows Used for Continuing Financing Activities in 2017 were $1.3 billion. AEP's net debt retirements were $338 million. The net retirements include retirements of $978 million of senior unsecured notes, $356 million of pollution control bonds, $258 million of securitization bonds, $835 million of other debt notes and repayments of $654 million of short term debt offset by issuances of $2.3 billion of senior unsecured notes, $242 million of pollution control bonds and $254 million of other debt notes. AEP also paid $46 million for a make whole premium on the early extinguishment of debt related to the sale of certain merchant generation assets. See Note 6 - Impairment, Disposition

and Assets and Liabilities Held for Sale for a complete discussion of this sale. AEP paid common stock dividends of $875 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Continuing Financing Activities in 2016 were $46 million. AEP’s net debt issuances were $930 million. The net issuances included an increase in short-term borrowing of $678 million, issuances of $950 million of senior unsecured notes, $191 million of pollution control bonds and $430 million of other debt notes offset by retirements of $507 million of senior unsecured notes, $289 million of securitization bonds, $251 million of pollution control bonds and $261 million of other debt notes. AEP paid common stock dividends of $830 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In October 2017, I&M retired $1 million of Notes Payable related to DCC Fuel.

In October 2017, AEP Texas retired $41 million of 5.625% Pollution Control Bonds due in 2017.

OFF-BALANCE SHEET ARRANGEMENTS

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

	September 30, 2017	December 31, 2016
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$812.4	$ 886.2
Railcars Maximum Potential Loss from Lease Agreement	16.9	18.4

For complete information on each of these off-balance sheet arrangements, see the “Off-balance Sheet Arrangements” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2016 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2016 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2016 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2017

The FASB issued ASU 2015-11 “Simplifying the Measurement of Inventory” simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management adopted ASU 2015-11 prospectively, effective January 1, 2017. There was no

impact on results of operations, financial position or cash flows at adoption.

The FASB issued ASU 2016-09 “Compensation – Stock Compensation” simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities

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and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income. 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.

Pronouncements Effective in the Future

The FASB issued ASU 2014-09 “Revenue from Contracts with Customers” clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. Management continues to analyze 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. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption.

The evaluation of revenue streams, new contracts and the new revenue standard’s disclosure requirements continues during the fourth quarter of 2017, in particular with respect to various ongoing industry implementation issues. Management will continue to analyze the related impacts to revenue recognition and monitor any new industry implementation issues that arise. Further, given industry conclusions related to implementation issues, including contributions in aid of construction and collectability, management does not anticipate changes to current accounting systems. Management plans to adopt ASU 2014-09 effective January 1, 2018.

The FASB issued ASU 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance 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. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU

2016-01 effective January 1, 2018.

The FASB issued ASU 2016-02 "Accounting for Leases" increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine

lease classification will remain the same, but will be more subjective under the new standard. The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented. 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, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. Management plans to adopt ASU 2016-02 effective January 1, 2019.

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

The FASB issued ASU 2016-18 “Restricted Cash” 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. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

The FASB issued ASU 2017-07 “Compensation - Retirement Benefits” 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 income statement 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 2016, AEP's actual non-service cost components were a credit of $66 million, of which approximately 37% 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 plans to adopt ASU 2017-07 effective January 1, 2018.

The FASB issued ASU 2017-12 "Derivatives and Hedging" 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 net income.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. Future pronouncements issued by the FASB could have an impact on future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

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

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

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer and Chief Risk Officer in

addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2016:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2017

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2016	$5.2	$ (118.2)	$ 164.2	$51.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(7.0)	3.4	(32.8)	(36.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	26.7	26.7
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	10.5	10.5
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	64.9	(23.2)	—	41.7
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2017	$63.1	$ (138.0)	$ 168.6	93.7
Commodity Cash Flow Hedge Contracts				(75.6)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				4.2
Fair Value Hedge Contracts				(1.4)
Collateral Deposits				13.5
Total MTM Derivative Contract Net Assets as of September 30, 2017				$34.4

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

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

Credit Risk

Credit risk is mitigated 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.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of September 30, 2017, credit exposure net of collateral to sub investment grade counterparties was approximately 7.9%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of September 30, 2017, the following table approximates AEP's counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$619.6	$ 2.2	$ 617.4	3	$ 352.2
Split Rating	5.6	—	5.6	2	5.6
Noninvestment Grade	—	—	—	—	—
No External Ratings:					
Internal Investment Grade	119.2	—	119.2	3	78.7
Internal Noninvestment Grade	75.4	11.5	63.9	3	40.5
Total as of September 30, 2017	$819.8	$ 13.7	$ 806.1		

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of September 30, 2017, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

Nine Months Ended September 30, 2017				Twelve Months Ended December 31, 2016			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.2	$0.4	$ 0.1	$0.1	$0.2	$1.1	$ 0.2	$0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2017	Twelve Months Ended December 31, 2016

End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.7	$6.5	$ 0.9	$0.3	$5.6	$8.4	$ 1.5	$0.4

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Management back-tests VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

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

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of September 30, 2017 and December 31, 2016, the estimated EaR on AEP's debt portfolio for the following twelve months was $30 million and $29 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Vertically Integrated Utilities	$2,453.8	$ 2,538.3	$6,819.3	$ 6,864.6
Transmission and Distribution Utilities	1,149.7	1,245.4	3,242.7	3,398.9
Generation & Marketing	441.5	823.3	1,386.8	2,192.5
Other Revenues	59.7	45.2	165.7	134.0
TOTAL REVENUES	4,104.7	4,652.2	11,614.5	12,590.0
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	707.4	880.1	1,865.3	2,236.1
Purchased Electricity for Resale	718.1	774.0	2,156.9	2,134.6
Other Operation	636.1	771.1	1,842.5	2,150.7
Maintenance	268.0	286.3	859.4	854.4
Asset Impairments and Other Related Charges	(2.5)	2,264.9	10.6	2,264.9
Gain on Sale of Merchant Generation Assets	—	—	(226.4)	—
Depreciation and Amortization	518.5	539.3	1,485.9	1,550.2
Taxes Other Than Income Taxes	272.6	264.4	792.0	767.9
TOTAL EXPENSES	3,118.2	5,780.1	8,786.2	11,958.8
OPERATING INCOME (LOSS)	986.5	(1,127.9)	2,828.3	631.2
Other Income (Expense):				
Interest and Investment Income	2.4	2.0	12.7	6.5
Carrying Costs Income	2.6	1.7	14.2	11.9
Allowance for Equity Funds Used During Construction	20.0	25.6	62.2	86.1
Gain on Sale of Equity Investment	12.4	—	12.4	—
Interest Expense	(223.3)	(225.3)	(668.0)	(667.2)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (CREDIT) AND EQUITY EARNINGS	800.6	(1,323.9)	2,261.8	68.5
Income Tax Expense (Credit)	264.0	(534.5)	797.8	(134.0)
Equity Earnings of Unconsolidated Subsidiaries	20.1	25.2	63.1	42.8
INCOME (LOSS) FROM CONTINUING OPERATIONS	556.7	(764.2)	1,527.1	245.3
LOSS FROM DISCONTINUED OPERATIONS, NET OF TAX	—	—	—	(2.5)
NET INCOME (LOSS)	556.7	(764.2)	1,527.1	242.8
Net Income Attributable to Noncontrolling Interests	12.0	1.6	15.2	5.3

EARNINGS (LOSS) ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$544.7	$(765.8)	$1,511.9	$237.5
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	491,840,724	491,697,809	491,781,643	491,422,921
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$1.11	$(1.56)	$3.07	$0.49
BASIC LOSS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	—	(0.01)
TOTAL BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.11	$(1.56)	$3.07	$0.48
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	492,986,304	491,813,858	492,428,586	491,596,861
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$1.10	$(1.56)	$3.07	$0.49
DILUTED LOSS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	—	(0.01)
TOTAL DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.10	$(1.56)	$3.07	$0.48
CASH DIVIDENDS DECLARED PER SHARE	$0.59	$0.56	$1.77	$1.68

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income (Loss)	$556.7	$(764.2)	$1,527.1	$242.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(8.1) and $(15.4) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(12.2) and $(11.2) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(15.0)	(28.6)	(22.6)	(20.8)
Securities Available for Sale, Net of Tax of $0.5 and $0.3 for the Three Months Ended September 30, 2017 and 2016, Respectively, and $1.5 and $1 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.9	0.5	2.7	1.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2017 and 2016, Respectively, and $0.4 and $0.2 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.3	0.2	0.8	0.4
TOTAL OTHER COMPREHENSIVE LOSS	(13.8)	(27.9)	(19.1)	(18.7)
TOTAL COMPREHENSIVE INCOME (LOSS)	542.9	(792.1)	1,508.0	224.1
Total Comprehensive Income Attributable to Noncontrolling Interests	12.0	1.6	15.2	5.3
TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$530.9	$(793.7)	$1,492.8	$218.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY - DECEMBER 31, 2015	511.4	$3,324.0	$6,296.5	$8,398.3	$ (127.1)	$ 13.2	$17,904.9
Issuance of Common Stock	0.6	4.3	29.9				34.2
Common Stock Dividends				(826.4)		(3.4)	(829.8)
Other Changes in Equity			3.6			6.0	9.6
Net Income				237.5		5.3	242.8
Other Comprehensive Loss					(18.7)		(18.7)
TOTAL EQUITY - SEPTEMBER 30, 2016	512.0	$3,328.3	$6,330.0	$7,809.4	$ (145.8)	$ 21.1	$17,343.0
TOTAL EQUITY - DECEMBER 31, 2016	512.0	$3,328.3	$6,332.6	$7,892.4	$ (156.3)	$ 23.1	$17,420.1
Common Stock Dividends				(872.3)		(2.7)	(875.0)
Other Changes in Equity			51.6			0.8	52.4
Net Income				1,511.9		15.2	1,527.1
Other Comprehensive Loss					(19.1)		(19.1)
TOTAL EQUITY - SEPTEMBER 30, 2017	512.0	$3,328.3	$6,384.2	$8,532.0	$ (175.4)	$ 36.4	$18,105.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$343.9	$ 210.5
Other Temporary Investments (September 30, 2017 and December 31, 2016 Amounts Include $300.5 and $322.5, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, EIS, Transource Energy and Sabine)	310.7	331.7
Accounts Receivable:		
Customers	522.7	705.1
Accrued Unbilled Revenues	187.3	158.7
Pledged Accounts Receivable – AEP Credit	967.6	972.7
Miscellaneous	99.9	118.1
Allowance for Uncollectible Accounts	(36.6)	(37.9)
Total Accounts Receivable	1,740.9	1,916.7
Fuel	354.2	423.8
Materials and Supplies	562.3	543.5
Risk Management Assets	146.1	94.5
Regulatory Asset for Under-Recovered Fuel Costs	153.5	156.6
Margin Deposits	105.7	79.9
Assets Held for Sale	—	1,951.2
Prepayments and Other Current Assets	350.5	325.5
TOTAL CURRENT ASSETS	4,067.8	6,033.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	20,739.3	19,848.9
Transmission	17,785.4	16,658.7
Distribution	19,589.4	18,900.8
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	3,614.1	3,444.3
Construction Work in Progress	3,710.0	3,183.9
Total Property, Plant and Equipment	65,438.2	62,036.6
Accumulated Depreciation and Amortization	17,121.7	16,397.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	48,316.5	45,639.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,640.0	5,625.5
Securitized Assets	1,287.8	1,486.1
Spent Nuclear Fuel and Decommissioning Trusts	2,433.0	2,256.2
Goodwill	52.5	52.5
Long-term Risk Management Assets	310.4	289.1
Deferred Charges and Other Noncurrent Assets	1,856.9	2,085.1

TOTAL OTHER NONCURRENT ASSETS	11,580.6	11,794.5
TOTAL ASSETS	$63,964.9	$ 63,467.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2017 and December 31, 2016
(dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Accounts Payable	$ 1,537.0	$ 1,688.5
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	673.0
Other Short-term Debt	309.3	1,040.0
Total Short-term Debt	1,059.3	1,713.0
Long-term Debt Due Within One Year (September 30, 2017 and December 31, 2016 Amounts Include $393.7 and $427.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,359.3	2,878.0
Risk Management Liabilities	69.4	53.4
Customer Deposits	346.6	343.2
Accrued Taxes	716.5	1,048.0
Accrued Interest	260.3	227.2
Regulatory Liability for Over-Recovered Fuel Costs	19.7	8.0
Liabilities Held for Sale	—	235.9
Other Current Liabilities	953.9	1,302.8
TOTAL CURRENT LIABILITIES	7,322.0	9,498.0
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2017 and December 31, 2016 Amounts Include $1421.5 and $1,737.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, and Sabine)	18,362.4	17,378.4
Long-term Risk Management Liabilities	352.7	316.2
Deferred Income Taxes	12,628.2	11,884.4
Regulatory Liabilities and Deferred Investment Tax Credits	3,959.6	3,751.3
Asset Retirement Obligations	1,919.3	1,830.6
Employee Benefits and Pension Obligations	468.9	614.1
Deferred Credits and Other Noncurrent Liabilities	837.0	774.6
TOTAL NONCURRENT LIABILITIES	38,528.1	36,549.6
TOTAL LIABILITIES	45,850.1	46,047.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEZZANINE EQUITY		

Contingently Redeemable Performance Share Awards			9.3	—
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2017	2016		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	512,048,663	512,048,520		
(20,206,368 and 20,336,592 Shares were Held in Treasury as of September 30, 2017 and December 31, 2016, Respectively)			3,328.3	3,328.3
Paid-in Capital			6,384.2	6,332.6
Retained Earnings			8,532.0	7,892.4
Accumulated Other Comprehensive Income (Loss)			(175.4)	(156.3)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			18,069.1	17,397.0
Noncontrolling Interests			36.4	23.1
TOTAL EQUITY			18,105.5	17,420.1
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$63,964.9	$ 63,467.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net Income	$1,527.1	$242.8
Loss from Discontinued Operations, Net of Tax	—	(2.5)
Income from Continuing Operations	1,527.1	245.3
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:		
Depreciation and Amortization	1,485.9	1,550.2
Deferred Income Taxes	740.9	(47.0)
Asset Impairments and Other Related Charges	10.6	2,264.9
Allowance for Equity Funds Used During Construction	(62.2)	(86.1)
Mark-to-Market of Risk Management Contracts	(56.2)	56.6
Amortization of Nuclear Fuel	104.8	109.7
Pension Contributions to Qualified Plan Trust	(93.3)	(84.8)
Property Taxes	291.4	288.3
Deferred Fuel Over/Under-Recovery, Net	81.0	(28.5)
Gain on Sale of Merchant Generation Assets	(226.4)	—
Gain on Sale of Equity Investment	(12.4)	—
Recovery of Ohio Capacity Costs	65.6	108.8
Provision for Refund – Global Settlement, Net	(93.3)	—
Change in Other Noncurrent Assets	(345.2)	(243.4)
Change in Other Noncurrent Liabilities	205.7	41.3
Changes in Certain Components of Continuing Working Capital:		
Accounts Receivable, Net	201.3	(240.8)
Fuel, Materials and Supplies	58.5	11.6
Accounts Payable	(91.0)	47.8
Accrued Taxes, Net	(310.1)	(393.0)
Other Current Assets	(98.2)	31.5
Other Current Liabilities	(260.3)	(211.4)
Net Cash Flows from Continuing Operating Activities	3,124.2	3,421.0
INVESTING ACTIVITIES		
Construction Expenditures	(3,778.2)	(3,387.0)
Change in Other Temporary Investments, Net	34.5	109.2
Purchases of Investment Securities	(1,855.8)	(2,454.5)
Sales of Investment Securities	1,808.6	2,427.0
Acquisitions of Nuclear Fuel	(73.2)	(127.6)
Proceeds from Sale of Merchant Generation Assets	2,159.6	—
Other Investing Activities	27.9	4.2
Net Cash Flows Used for Continuing Investing Activities	(1,676.6)	(3,428.7)

FINANCING ACTIVITIES		
Issuance of Common Stock	—	34.2
Issuance of Long-term Debt	2,742.7	1,559.6
Change in Short-term Debt, Net	(653.7)	678.3
Retirement of Long-term Debt	(2,427.2)	(1,307.6)
Make Whole Premium on Extinguishment of Long-term Debt	(46.1)	—
Principal Payments for Capital Lease Obligations	(50.5)	(81.9)
Dividends Paid on Common Stock	(875.0)	(829.8)
Other Financing Activities	(4.4)	(6.8)
Net Cash Flows from (Used for) Continuing Financing Activities	(1,314.2)	46.0
Net Cash Flows Used for Discontinued Operating Activities	—	(2.5)
Net Cash Flows from Discontinued Investing Activities	—	—
Net Cash Flows from Discontinued Financing Activities	—	—
Net Increase in Cash and Cash Equivalents	133.4	35.8
Cash and Cash Equivalents at Beginning of Period	210.5	176.4
Cash and Cash Equivalents at End of Period	$343.9	$212.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30,	
	2017	2016
	(in millions)	
Plant In Service	$4,684.4	$3,260.7
CWIP	1,383.1	1,328.6
Accumulated Depreciation	151.5	86.6
Total Transmission Property, Net	$5,916.0	$4,502.7

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$52.4
Changes in Transmission Revenues:	
Transmission Revenues	42.0
Total Change in Transmission Revenues	42.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.4)
Depreciation and Amortization	(8.0)
Taxes Other Than Income Taxes	(4.9)
Interest Income	0.1
Allowance for Equity Funds Used During Construction	(1.6)
Interest Expense	(5.9)
Total Change in Expenses and Other	(30.7)
Income Tax Expense	(3.8)
Third Quarter of 2017	$59.9

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 $42 million primarily due to a $40 million increase in formula rates driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $10 million primarily due to increased transmission investment.

- Depreciation and Amortization expenses increased $8 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased property taxes as a result of additional transmission investment.
- Interest Expense increased $6 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $4 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$153.0
Changes in Transmission Revenues:	
Transmission Revenues	191.4
Total Change in Transmission Revenues	191.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(19.8)
Depreciation and Amortization	(23.4)
Taxes Other Than Income Taxes	(16.6)
Interest Income	0.3
Allowance for Equity Funds Used During Construction	(3.7)
Interest Expense	(16.3)
Total Change in Expenses and Other	(79.5)
Income Tax Expense	(40.6)
Nine Months Ended September 30, 2017	$224.3

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 $191 million primarily due to the current year favorable impact of the modification of the PJM OATT formula rates combined with an increase driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $20 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $23 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $17 million primarily due to increased property taxes as a result of additional transmission investment.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to the FERC transmission complaint and an increase in the amount of short term debt, offset by an increase in the CWIP balance.
- Interest Expense increased $16 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $41 million primarily due to an increase in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Transmission Revenues	$35.9	$33.5	$99.2	$89.6
Sales to AEP Affiliates	131.4	91.8	450.2	268.4
TOTAL REVENUES	167.3	125.3	549.4	358.0
EXPENSES				
Other Operation	18.4	7.5	38.8	21.0
Maintenance	1.4	1.9	6.8	4.8
Depreciation and Amortization	24.8	16.8	70.9	47.5
Taxes Other Than Income Taxes	27.6	22.7	82.0	65.4
TOTAL EXPENSES	72.2	48.9	198.5	138.7
OPERATING INCOME	95.1	76.4	350.9	219.3
Other Income (Expense):				
Interest Income	0.2	0.1	0.5	0.2
Allowance for Equity Funds Used During Construction	11.7	13.3	36.0	39.7
Interest Expense	(16.9)	(11.0)	(48.6)	(32.3)
INCOME BEFORE INCOME TAX EXPENSE	90.1	78.8	338.8	226.9
Income Tax Expense	30.2	26.4	114.5	73.9
NET INCOME	$59.9	$52.4	$224.3	$153.0

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total Member's Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2015	$1,243.0	$ 309.9	$ 1,552.9
Capital Contributions from Member	116.0		116.0
Net Income		153.0	153.0
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2016	$1,359.0	$ 462.9	$ 1,821.9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	$1,455.0	$ 502.6	$ 1,957.6
Capital Contributions from Member	185.5		185.5
Net Income		224.3	224.3
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2017	$1,640.5	$ 726.9	$ 2,367.4

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Advances to Affiliates	$ 290.9	$ 67.1
Accounts Receivable:		
Customers	19.5	11.3
Affiliated Companies	102.8	66.6
Total Accounts Receivable	122.3	77.9
Materials and Supplies	16.0	5.0
Accrued Tax Benefits	12.7	26.0
Prepayments and Other Current Assets	8.1	2.8
TOTAL CURRENT ASSETS	450.0	178.8
TRANSMISSION PROPERTY		
Transmission Property	4,570.9	3,973.5
Other Property, Plant and Equipment	113.5	99.4
Construction Work in Progress	1,383.1	981.3
Total Transmission Property	6,067.5	5,054.2
Accumulated Depreciation and Amortization	151.5	99.6
TOTAL TRANSMISSION PROPERTY – NET	5,916.0	4,954.6
OTHER NONCURRENT ASSETS		
Accounts Receivable - Affiliated Companies	13.8	—
Regulatory Assets	138.0	112.3
Deferred Property Taxes	29.8	102.2
Deferred Charges and Other Noncurrent Assets	1.3	1.9
TOTAL OTHER NONCURRENT ASSETS	182.9	216.4
TOTAL ASSETS	$ 6,548.9	$ 5,349.8

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Advances from Affiliates	$ 32.8	$ 4.1
Accounts Payable:		
General	233.2	289.7
Affiliated Companies	50.0	43.1
Accrued Taxes	112.5	191.8
Accrued Interest	28.9	10.5
Other Current Liabilities	10.4	10.9
TOTAL CURRENT LIABILITIES	467.8	550.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,550.0	1,932.0
Deferred Income Taxes	1,073.1	862.1
Regulatory Liabilities	60.5	44.0
Deferred Credits and Other Noncurrent Liabilities	30.1	4.0
TOTAL NONCURRENT LIABILITIES	3,713.7	2,842.1
TOTAL LIABILITIES	4,181.5	3,392.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	1,640.5	1,455.0
Retained Earnings	726.9	502.6
TOTAL MEMBER'S EQUITY	2,367.4	1,957.6
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 6,548.9	$ 5,349.8

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net Income	$224.3	$153.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	70.9	47.5
Deferred Income Taxes	193.0	161.2
Allowance for Equity Funds Used During Construction	(36.0)	(39.7)
Property Taxes	72.4	63.5
Long-term Accounts Receivable - Affiliated	(13.8)	—
Change in Other Noncurrent Assets	7.6	(6.4)
Change in Other Noncurrent Liabilities	25.7	0.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(44.4)	(43.3)
Materials and Supplies	(11.0)	(1.5)
Accounts Payable	8.6	(1.7)
Accrued Taxes, Net	(66.0)	61.2
Accrued Interest	18.4	11.3
Other Current Assets	(5.3)	(0.1)
Other Current Liabilities	0.5	0.1
Net Cash Flows from Operating Activities	444.9	405.7
INVESTING ACTIVITIES		
Construction Expenditures	(1,050.7)	(799.8)
Change in Advances to Affiliates, Net	(223.8)	83.7
Other Investing Activities	(2.9)	(4.6)
Net Cash Flows Used for Investing Activities	(1,277.4)	(720.7)
FINANCING ACTIVITIES		
Capital Contributions from Member	185.5	116.0
Issuance of Long-term Debt - Nonaffiliated	618.3	—
Change in Advances from Affiliates, Net	28.7	199.0
Net Cash Flows from Financing Activities	832.5	315.0
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	$28.6	$20.0
Net Cash Paid (Received) for Income Taxes	(93.4)	(209.8)
Construction Expenditures Included in Current Liabilities as of September 30,	239.0	204.8

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 118.

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	2,488	2,845	7,829	8,743
Commercial	1,673	1,823	4,805	5,125
Industrial	2,431	2,391	7,106	7,022
Miscellaneous	202	217	613	637
Total Retail	6,794	7,276	20,353	21,527
Wholesale	994	1,029	2,684	2,413
Total KWhs	7,788	8,305	23,037	23,940

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	1,000	1,433
Normal - Heating (b)	2	2	1,420	1,437
Actual - Cooling (c)	805	1,049	1,180	1,437
Normal - Cooling (b)	812	808	1,179	1,177

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

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Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$104.1
Changes in Gross Margin:	
Retail Margins	(40.6)
Off-system Sales	(1.0)
Transmission Revenues	1.8
Other Revenues	0.5
Total Change in Gross Margin	(39.3)
Changes in Expenses and Other:	
Other Operation and Maintenance	12.9
Depreciation and Amortization	(4.7)
Taxes Other Than Income Taxes	(0.3)
Carrying Costs Income	0.4
Allowance for Equity Funds Used During Construction	(1.8)
Interest Expense	(0.8)
Total Change in Expenses and Other	5.7
Income Tax Expense	15.5
Third Quarter of 2017	$86.0

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

- Retail Margins decreased $41 million primarily due to the following:
- A $25 million decrease in weather-related usage primarily driven by a 23% decrease in cooling degree days.
- An $8 million decrease in weather-normalized margin occurring across all retail classes.
- A $6 million decrease primarily due to a decrease in rates in West Virginia and Virginia. This decrease is partially offset by a corresponding decrease in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses decreased $13 million primarily due to the following:
- A $7 million decrease in storm-related expenses.
- A $4 million decrease in generation plant maintenance expenses.
- Depreciation and Amortization expenses increased $5 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $16 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$303.8
Changes in Gross Margin:	
Retail Margins	(93.7)
Off-system Sales	(0.1)
Transmission Revenues	25.9
Other Revenues	3.2
Total Change in Gross Margin	(64.7)
Changes in Expenses and Other:	
Other Operation and Maintenance	(8.3)
Depreciation and Amortization	(14.1)
Taxes Other Than Income Taxes	0.6
Interest Income	0.3
Carrying Costs Income	0.8
Allowance for Equity Funds Used During Construction	(2.9)
Interest Expense	(2.8)
Total Change in Expenses and Other	(26.4)
Income Tax Expense	36.0
Nine Months Ended September 30, 2017	$248.7

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

- Retail Margins decreased $94 million primarily due to the following:
  - A $72 million decrease in weather-related usage primarily driven by a 30% decrease in heating degree days and an 18% decrease in cooling degree days.
  - A $14 million decrease primarily due to prior year recognition of deferred billing in West Virginia as approved by the WVPSC.
  - A $3 million decrease in weather-normalized margin primarily driven by the commercial class.
- Transmission Revenues increased $26 million primarily due to increase in formula rates driven by continued investment in transmission assets. This increase is partially offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $8 million primarily due to the following:
  - A $13 million increase in recoverable PJM transmission expenses. This increase in expense is offset within Gross Margin above.
  - A $6 million gain on the sale of property in 2016.

These increases were partially offset by:

- An $8 million decrease in storm-related expenses.
- A $5 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased $14 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $36 million primarily due to a decrease in pretax book income and the recording of federal income tax adjustments.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$674.4	$739.0	$2,045.0	$2,153.3
Sales to AEP Affiliates	41.9	36.4	130.6	109.0
Other Revenues	3.0	2.8	11.8	9.4
TOTAL REVENUES	719.3	778.2	2,187.4	2,271.7
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	178.6	190.1	498.3	494.1
Purchased Electricity for Resale	61.1	69.2	217.1	240.9
Other Operation	115.7	117.6	366.2	349.4
Maintenance	55.8	66.8	187.8	196.3
Depreciation and Amortization	102.8	98.1	304.1	290.0
Taxes Other Than Income Taxes	32.3	32.0	93.3	93.9
TOTAL EXPENSES	546.3	573.8	1,666.8	1,664.6
OPERATING INCOME	173.0	204.4	520.6	607.1
Other Income (Expense):				
Interest Income	0.3	0.3	1.1	0.8
Carrying Costs Income	0.4	—	1.0	0.2
Allowance for Equity Funds Used During Construction	2.7	4.5	6.2	9.1
Interest Expense	(47.2)	(46.4)	(143.5)	(140.7)
INCOME BEFORE INCOME TAX EXPENSE	129.2	162.8	385.4	476.5
Income Tax Expense	43.2	58.7	136.7	172.7
NET INCOME	$86.0	$104.1	$248.7	$303.8

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 118.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$86.0	$104.1	$248.7	$303.8
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.1)	(0.2)	(0.5)	(0.6)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.4) and $(0.5) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.3)	(0.3)	(0.9)	(1.0)
TOTAL OTHER COMPREHENSIVE LOSS	(0.4)	(0.5)	(1.4)	(1.6)
TOTAL COMPREHENSIVE INCOME	$85.6	$103.6	$247.3	$302.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER’S EQUITY - DECEMBER 31, 2015	$ 260.4	$1,828.7	$1,388.7	$ (2.8)	$3,475.0
Common Stock Dividends			(225.0)		(225.0)
Net Income			303.8		303.8
Other Comprehensive Loss				(1.6)	(1.6)
TOTAL COMMON SHAREHOLDER’S EQUITY - SEPTEMBER 30, 2016	$ 260.4	$1,828.7	$1,467.5	$ (4.4)	$3,552.2
TOTAL COMMON SHAREHOLDER’S EQUITY - DECEMBER 31, 2016	$ 260.4	$1,828.7	$1,502.8	$ (8.4)	$3,583.5
Common Stock Dividends			(90.0)		(90.0)
Net Income			248.7		248.7
Other Comprehensive Loss				(1.4)	(1.4)
TOTAL COMMON SHAREHOLDER’S EQUITY - SEPTEMBER 30, 2017	$ 260.4	$1,828.7	$1,661.5	$ (9.8)	$3,740.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$2.9	$ 2.7
Restricted Cash for Securitized Funding	8.3	15.8
Advances to Affiliates	23.6	24.1
Accounts Receivable:		
Customers	96.8	131.4
Affiliated Companies	59.5	54.4
Accrued Unbilled Revenues	41.1	52.7
Miscellaneous	1.3	0.9
Allowance for Uncollectible Accounts	(2.7)	(3.5)
Total Accounts Receivable	196.0	235.9
Fuel	96.3	112.0
Materials and Supplies	100.8	98.8
Risk Management Assets	30.3	2.6
Accrued Tax Benefits	0.4	4.2
Regulatory Asset for Under-Recovered Fuel Costs	63.5	68.4
Margin Deposits	11.8	17.5
Prepayments and Other Current Assets	18.2	9.7
TOTAL CURRENT ASSETS	552.1	591.7
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,393.7	6,332.8
Transmission	2,904.4	2,796.9
Distribution	3,703.5	3,569.1
Other Property, Plant and Equipment	409.8	373.5
Construction Work in Progress	493.5	390.3
Total Property, Plant and Equipment	13,904.9	13,462.6
Accumulated Depreciation and Amortization	3,836.7	3,636.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,068.2	9,825.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,100.1	1,121.1
Securitized Assets	288.0	305.3
Long-term Risk Management Assets	0.6	—
Deferred Charges and Other Noncurrent Assets	113.6	133.3
TOTAL OTHER NONCURRENT ASSETS	1,502.3	1,559.7
TOTAL ASSETS	$12,122.6	$ 11,977.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$69.5	$ 79.6
Accounts Payable:		
General	235.4	253.7
Affiliated Companies	75.5	82.6
Long-term Debt Due Within One Year - Nonaffiliated	149.2	503.1
Risk Management Liabilities	0.9	0.3
Customer Deposits	84.0	83.1
Accrued Taxes	64.0	107.6
Accrued Interest	71.4	40.6
Other Current Liabilities	99.2	129.5
TOTAL CURRENT LIABILITIES	849.1	1,280.1
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	3,830.1	3,530.8
Long-term Risk Management Liabilities	0.3	0.9
Deferred Income Taxes	2,796.7	2,672.3
Regulatory Liabilities and Deferred Investment Tax Credits	634.4	627.8
Asset Retirement Obligations	101.2	108.8
Employee Benefits and Pension Obligations	92.2	108.5
Deferred Credits and Other Noncurrent Liabilities	77.8	64.5
TOTAL NONCURRENT LIABILITIES	7,532.7	7,113.6
TOTAL LIABILITIES	8,381.8	8,393.7
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	1,661.5	1,502.8
Accumulated Other Comprehensive Income (Loss)	(9.8)	(8.4)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,740.8	3,583.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$12,122.6	$ 11,977.2

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 118.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2017			2016		
OPERATING ACTIVITIES						
Net Income	$	248.7		$	303.8	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	304.1			290.0		
Deferred Income Taxes	121.7			100.9		
Carrying Costs Income	(1.0		)	(0.2		)
Allowance for Equity Funds Used During Construction	(6.2		)	(9.1		)
Mark-to-Market of Risk Management Contracts	(28.3		)	18.4		
Pension Contributions to Qualified Plan Trust	(10.2		)	(8.8		)
Property Taxes	29.8			29.2		
Deferred Fuel Over/Under-Recovery, Net	4.9			19.0		
Change in Other Noncurrent Assets	8.3			(5.1		)
Change in Other Noncurrent Liabilities	7.9			(23.0		)
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	39.9			(20.5		)
Fuel, Materials and Supplies	14.0			(1.2		)
Accounts Payable	6.2			4.9		
Accrued Taxes, Net	(44.2		)	(13.9		)
Other Current Assets	(2.5		)	(0.2		)
Other Current Liabilities	9.1			(4.1		)
Net Cash Flows from Operating Activities	702.2			680.1		
INVESTING ACTIVITIES						
Construction Expenditures	(560.0		)	(472.7		)
Change in Restricted Cash for Securitized Funding	7.5			7.0		
Change in Advances to Affiliates, Net	0.5			1.2		
Other Investing Activities	11.8			10.6		
	(540.2		)	(453.9		)

Net Cash Flows Used for Investing Activities		
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	320.9	314.1
Change in Advances from Affiliates, Net	(10.1)	(96.9)
Retirement of Long-term Debt - Nonaffiliated	(377.9)	(213.6)
Principal Payments for Capital Lease Obligations	(5.2)	(4.7)
Dividends Paid on Common Stock	(90.0)	(225.0)
Other Financing Activities	0.5	0.4
Net Cash Flows Used for Financing Activities	(161.8)	(225.7)
Net Increase in Cash and Cash Equivalents	0.2	0.5
Cash and Cash Equivalents at Beginning of Period	2.7	2.8
Cash and Cash Equivalents at End of Period	$ 2.9	$ 3.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 107.1	$ 113.2
Net Cash Paid for Income Taxes	24.4	55.8
Noncash Acquisitions Under Capital Leases	2.9	2.1
Construction Expenditures Included in Current Liabilities as of September 30,	107.2	66.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	1,404	1,619	4,015	4,344
Commercial	1,313	1,405	3,640	3,780
Industrial	1,978	1,996	5,793	5,876
Miscellaneous	16	15	50	50
Total Retail	4,711	5,035	13,498	14,050
Wholesale	2,807	2,613	8,567	7,038
Total KWhs	7,518	7,648	22,065	21,088

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	1,816	2,196
Normal - Heating (b)	11	10	2,430	2,449
Actual - Cooling (c)	504	741	764	1,011
Normal - Cooling (b)	574	571	835	835

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

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Third Quarter of 2017 Compared to Third Quarter of 2016

Reconciliation of Third Quarter of 2016 to Third Quarter of 2017 Net Income (in millions)	
Third Quarter of 2016	$75.4
Changes in Gross Margin:	
Retail Margins (a)	(4.4)
Transmission Revenues	(6.2)
Other Revenues	(1.5)
Total Change in Gross Margin	(12.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.4)
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(5.9)
Taxes Other Than Income Taxes	(1.4)
Other Income	0.1
Interest Expense	(0.8)
Total Change in Expenses and Other	(4.9)
Income Tax Expense	6.5
Third Quarter of 2017	$64.9

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

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

- Retail Margins decreased $4 million primarily due to the following:
- An $18 million decrease in weather-related usage primarily due to a 32% decrease in cooling degree days.
- A $6 million decrease in weather-normalized margins.
- A $5 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to formula rate adjustments.
- A $2 million decrease due to increased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.

These decreases were partially offset by:

- A $13 million increase from rate proceedings in the I&M service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
- A $9 million increase related to over/under recovery of riders.
- A $2 million decrease in PJM related expenses primarily due to reduced FTRs.
- Transmission Revenues decreased $6 million primarily due to an annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to the following:
- A $9 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase in expense is offset within Retail Margins above.
- A $3 million increase in nuclear expenses primarily due to an increase in refueling outage amortization and refueling outage expenses not deferred, partially offset by a decrease in employee-related expenses.

These increases were partially offset by:

- A $3 million decrease in distribution expenses primarily due to decreased vegetation management.
- Asset Impairments and Other Related Charges decreased $11 million due to the impairment of I&M's Price River coal reserves in 2016.
- Depreciation and Amortization expenses increased $6 million primarily due to higher depreciable base.
- Income Tax Expense decreased $7 million primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30,
2016 to Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$201.4
Changes in Gross Margin:	
Retail Margins (a)	(11.2)
Off-system Sales	0.5
Transmission Revenues	(23.0)
Other Revenues	(2.1)
Total Change in Gross Margin	(35.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(39.3)
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(11.6)
Taxes Other Than Income Taxes	3.2
Other Income	(0.4)
Interest Expense	(6.7)
Total Change in Expenses and Other	(44.3)
Income Tax Expense	22.5
Nine Months Ended September 30, 2017	$143.8

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

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

- Retail Margins decreased $11 million primarily due to the following:
- A $33 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to an annual formula rate true-up and other rate adjustments.
- A $29 million decrease in weather-related usage primarily due to a 24% decrease in cooling degree days and a 17% decrease in heating degree days.
- An $11 million decrease in weather-normalized margins.
- A $5 million decrease due to increased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.

These decreases were partially offset by:

- A $47 million increase from rate proceedings in the I&M service territory. The increase in retail margins relating to riders has corresponding increases in other items below.
- A $19 million increase related to over/under recovery of riders.
- A $2 million decrease in PJM related expenses primarily due to reduced FTRs.
- Transmission Revenues decreased $23 million primarily due to an annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.

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

- Other Operation and Maintenance expenses increased $39 million primarily due to the following:
- A $38 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase in expense was offset within Retail Margins above.
- A $7 million increase in nuclear expenses primarily due to an increase in refueling outage amortization, partially offset by refueling outage expenses not deferred, a decrease in employee-related expenses and material write-off.
- A $3 million increase in distribution expenses primarily due to increased vegetation management.

These increases were partially offset by:

- An $8 million decrease primarily due to employee-related expenses.
- Asset Impairments and Other Related Charges decreased $11 million due to the impairment of I&M's Price River coal reserves in 2016.
- Depreciation and Amortization expenses increased $12 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes decreased $3 million primarily due to property taxes.
- Interest Expense increased $7 million primarily due to higher long-term debt balances.
- Income Tax Expense decreased $23 million primarily due to a decrease in pretax book income, partially offset by the recording of favorable federal income tax adjustments in 2016.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$537.0	$574.7	$1,527.4	$1,570.8
Other Revenues – Affiliated	17.1	19.5	48.2	68.7
Other Revenues – Nonaffiliated	3.6	3.4	9.9	13.2
TOTAL REVENUES	557.7	597.6	1,585.5	1,652.7
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	76.4	91.3	238.2	236.8
Purchased Electricity for Resale	32.9	43.7	101.2	134.3
Purchased Electricity from AEP Affiliates	62.4	64.5	166.2	165.9
Other Operation	140.5	138.9	434.2	413.9
Maintenance	51.5	45.7	153.6	134.6
Asset Impairments and Other Related Charges	—	10.5	—	10.5
Depreciation and Amortization	55.0	49.1	154.8	143.2
Taxes Other Than Income Taxes	23.9	22.5	68.3	71.5
TOTAL EXPENSES	442.6	466.2	1,316.5	1,310.7
OPERATING INCOME	115.1	131.4	269.0	342.0
Other Income (Expense):				
Interest Income	2.4	1.7	11.5	9.1
Allowance for Equity Funds Used During Construction	3.5	4.1	8.1	10.9
Interest Expense	(27.5)	(26.7)	(83.0)	(76.3)
INCOME BEFORE INCOME TAX EXPENSE	93.5	110.5	205.6	285.7
Income Tax Expense	28.6	35.1	61.8	84.3
NET INCOME	$64.9	$75.4	$143.8	$201.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Net Income	$64.9	$75.4	$143.8	$201.4
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2017 and 2016, Respectively, and $0.5 and $0.5 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.3	0.3	1.0	1.0
TOTAL COMPREHENSIVE INCOME	$65.2	$75.7	$144.8	$202.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 56.6	$ 980.9	$ 1,015.6	$ (16.7)	$ 2,036.4
Common Stock Dividends			(93.8)		(93.8)
Net Income			201.4		201.4
Other Comprehensive Income				1.0	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 56.6	$ 980.9	$ 1,123.2	$ (15.7)	$ 2,145.0
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 56.6	$ 980.9	$ 1,130.5	$ (16.2)	$ 2,151.8
Common Stock Dividends			(93.7)		(93.7)
Net Income			143.8		143.8
Other Comprehensive Income				1.0	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 56.6	$ 980.9	$ 1,180.6	$ (15.2)	$ 2,202.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$1.3	$ 1.2
Advances to Affiliates	12.6	12.5
Accounts Receivable:		
Customers	42.1	60.2
Affiliated Companies	42.8	51.0
Accrued Unbilled Revenues	8.4	1.5
Miscellaneous	1.1	0.7
Allowance for Uncollectible Accounts	(0.3)	—
Total Accounts Receivable	94.1	113.4
Fuel	32.3	32.3
Materials and Supplies	156.5	150.8
Risk Management Assets	11.6	3.5
Accrued Tax Benefits	34.5	37.7
Regulatory Asset for Under-Recovered Fuel Costs	12.3	26.1
Accrued Reimbursement of Spent Nuclear Fuel Costs	11.0	22.1
Prepayments and Other Current Assets	26.9	19.9
TOTAL CURRENT ASSETS	393.1	419.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,399.9	4,056.1
Transmission	1,491.4	1,472.8
Distribution	2,000.1	1,899.3
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	555.9	550.2
Construction Work in Progress	478.9	654.2
Total Property, Plant and Equipment	8,926.2	8,632.6
Accumulated Depreciation, Depletion and Amortization	3,022.5	3,005.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,903.7	5,627.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	941.0	916.6
Spent Nuclear Fuel and Decommissioning Trusts	2,433.0	2,256.2
Long-term Risk Management Assets	0.5	—
Deferred Charges and Other Noncurrent Assets	95.9	121.5
TOTAL OTHER NONCURRENT ASSETS	3,470.4	3,294.3
TOTAL ASSETS	$9,767.2	$ 9,341.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Advances from Affiliates	$177.5	$ 215.2
Accounts Payable:		
General	168.6	179.0
Affiliated Companies	72.2	75.6
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2017 and December 31, 2016 Amounts Include $83.7 and $130.9, Respectively, Related to DCC Fuel)	462.1	209.3
Risk Management Liabilities	2.0	0.3
Customer Deposits	37.3	34.3
Accrued Taxes	43.8	77.2
Accrued Interest	14.3	31.7
Obligations Under Capital Leases	7.3	9.4
Other Current Liabilities	114.3	123.4
TOTAL CURRENT LIABILITIES	1,099.4	955.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,196.4	2,262.1
Long-term Risk Management Liabilities	0.2	0.8
Deferred Income Taxes	1,681.8	1,527.4
Regulatory Liabilities and Deferred Investment Tax Credits	1,169.6	1,065.5
Asset Retirement Obligations	1,307.4	1,257.9
Deferred Credits and Other Noncurrent Liabilities	109.5	120.4
TOTAL NONCURRENT LIABILITIES	6,464.9	6,234.1
TOTAL LIABILITIES	7,564.3	7,189.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,180.6	1,130.5
Accumulated Other Comprehensive Income (Loss)	(15.2)	(16.2)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,202.9	2,151.8
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,767.2	$ 9,341.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2017			2016		
OPERATING ACTIVITIES						
Net Income	$	143.8		$	201.4	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	154.8			143.2		
Deferred Income Taxes	132.2			116.2		
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	15.5			(17.4		)
Asset Impairments and Other Related Charges	—			10.5		
Allowance for Equity Funds Used During Construction	(8.1		)	(10.9		)
Mark-to-Market of Risk Management Contracts	(7.5		)	0.5		
Amortization of Nuclear Fuel	104.8			109.7		
Pension Contribution to Qualified Plan Trust	(13.0		)	(12.7		)
Deferred Fuel Over/Under-Recovery, Net	22.0			6.1		
Change in Other Noncurrent Assets	(42.1		)	—		
Change in Other Noncurrent Liabilities	40.9			30.0		
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	19.3			17.0		
Fuel, Materials and Supplies	(4.1		)	(1.1		)
Accounts Payable	16.6			(17.9		)
Accrued Taxes, Net	(30.2		)	(16.5		)
Other Current Assets	8.0			6.7		
Other Current Liabilities	(28.6		)	(27.8		)
Net Cash Flows from Operating Activities	524.3			537.0		
INVESTING ACTIVITIES						
Construction Expenditures	(469.2		)	(405.1		)
	(0.1		)	(0.7		)

Change in Advances to Affiliates, Net				
Purchases of Investment Securities	(1,842.2	)	(2,452.9	)
Sales of Investment Securities	1,808.6		2,427.0	
Acquisitions of Nuclear Fuel	(73.2	)	(127.6	)
Other Investing Activities	7.3		7.8	
Net Cash Flows Used for Investing Activities	(568.8	)	(551.5	)
FINANCING ACTIVITIES				
Issuance of Long-term Debt – Nonaffiliated	411.1		482.7	
Change in Advances from Affiliates, Net	(37.7	)	(268.0	)
Retirement of Long-term Debt – Nonaffiliated	(227.1	)	(76.8	)
Principal Payments for Capital Lease Obligations	(8.7	)	(29.8	)
Dividends Paid on Common Stock	(93.7	)	(93.8	)
Other Financing Activities	0.7		0.7	
Net Cash Flows from Financing Activities	44.6		15.0	
Net Increase in Cash and Cash Equivalents	0.1		0.5	
Cash and Cash Equivalents at Beginning of Period	1.2		1.1	
Cash and Cash Equivalents at End of Period	$ 1.3		$ 1.6	
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$ 92.0		$ 85.6	
Net Cash Paid (Received) for Income Taxes	(69.6	)	(36.0	)
Noncash Acquisitions Under Capital Leases	5.9		16.8	
Construction Expenditures Included in Current Liabilities as of September 30,	74.5		83.4	
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.6		0.3	
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2.8		0.1	

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	3,644	4,380	10,198	11,209
Commercial	3,806	4,114	10,789	11,158
Industrial	3,708	3,610	10,967	10,671
Miscellaneous	28	27	87	89
Total Retail (a)	11,186	12,131	32,041	33,127
Wholesale (b)	585	654	1,749	1,389
Total KWhs	11,771	12,785	33,790	34,516

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

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	1,500	1,929
Normal - Heating (b)	6	7	2,091	2,110
Actual - Cooling (c)	642	900	957	1,209
Normal - Cooling (b)	670	664	960	956

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

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Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$99.9
Changes in Gross Margin:	
Retail Margins	(74.1)
Off-system Sales	(12.0)
Transmission Revenues	(1.8)
Other Revenues	(2.1)
Total Change in Gross Margin	(90.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	59.3
Depreciation and Amortization	12.1
Taxes Other Than Income Taxes	1.5
Carrying Costs Income	(0.4)
Allowance for Equity Funds Used During Construction	0.6
Interest Expense	1.5
Total Change in Expenses and Other	74.6
Income Tax Expense	(1.9)
Third Quarter of 2017	$82.6

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

- Retail Margins decreased $74 million primarily due to the following:
  - A $52 million decrease in revenues associated with the Universal Service Fund (USF) surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - An $18 million net decrease in recovery of equity carrying charges related to the Phase-In Recovery Rider (PIRR), net of associated amortizations.
  - An $8 million decrease in revenues associated with smart grid riders. This decrease was offset in various expenses below.
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes below.

  These decreases were partially offset by:
  - A $12 million favorable impact due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net expense related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- Margins from Off-system Sales decreased $12 million due to current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $59 million primarily due to the following:
  - A $52 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $3 million decrease in recoverable smart grid expenses. This decrease was offset in Retail Margins above.
- Depreciation and Amortization expenses decreased $12 million primarily due to the following:
  - A $5 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $4 million decrease in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015.
  - A $4 million decrease in recoverable smart grid depreciation expenses. This decrease was offset in Retail Margins above.
- Taxes Other Than Income Taxes decreased $2 million primarily due to the following:
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Retail Margins above.

  This decrease was partially offset by:
  - A $3 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$244.7
Changes in Gross Margin:	
Retail Margins	(153.8)
Off-system Sales	(27.9)
Transmission Revenues	(2.9)
Other Revenues	(0.3)
Total Change in Gross Margin	(184.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	144.3
Depreciation and Amortization	23.3
Taxes Other Than Income Taxes	(2.1)
Interest Income	1.0
Carrying Costs Income	(1.0)
Allowance for Equity Funds Used During Construction	0.4
Interest Expense	10.9
Total Change in Expenses and Other	176.8
Income Tax Expense	(5.5)
Nine Months Ended September 30, 2017	$231.1

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

- Retail Margins decreased $154 million primarily due to the following:
- A $140 million decrease in revenues associated with the USF surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- A $21 million decrease due to a prior year reversal of a regulatory provision resulting from a favorable court decision.
- A $13 million decrease in revenues associated with smart grid riders. This decrease was offset in various expenses below.
- A $9 million net decrease in recovery of equity carrying charges related to the PIRR, net of associated amortizations.
- A $7 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes below.
- A $3 million decrease in transmission cost recovery rider revenues. This decrease was offset in Depreciation and Amortization below.

These decreases were partially offset by:

- A $46 million favorable impact due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net expense related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- A $6 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.

- Margins from Off-system Sales decreased $28 million primarily due to the following:
  - A $46 million decrease due to current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

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This decrease was partially offset by:

- An $18 million increase primarily due to the impact of prior year losses from a power contract with OVEC which was not included in the OVEC PPA rider.

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

- Other Operation and Maintenance expenses decreased $144 million primarily due to the following:
- A $140 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
- An $8 million decrease in recoverable smart grid expenses. This decrease was offset in Retail Margins above.
- A $7 million decrease in securitized customer accounts receivable expenses.
- A $3 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $12 million increase in PJM expenses related to the annual formula rate true-up that will be recovered in future periods.
- Depreciation and Amortization expenses decreased $23 million primarily due to the following:
- An $11 million decrease in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015.
- An $8 million decrease in recoveries of transmission cost rider carrying costs. This decrease was partially offset in Retail Margins above.
- A $7 million decrease in recoverable DIR depreciation expense in Ohio.
- A $5 million decrease in recoverable smart grid depreciation expenses. This decrease was offset in Retail Margins above.

These decreases were partially offset by:

- A $5 million increase in depreciation expense due to an increase in depreciable base of transmission and distribution assets.
- A $3 million increase due to amortization of capitalized software costs.
- Taxes Other Than Income Taxes increased $2 million primarily due to the following:
- A $9 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

This increase was partially offset by:

- A $7 million decrease in state excise taxes due to a decrease in metered KWh. This decrease was offset by a corresponding decrease in Retail Margins above.
- Interest Expense decreased $11 million primarily due to the maturity of a senior unsecured note in June 2016.
- Income Tax Expense increased $6 million primarily due to other book/tax differences which are accounted for on a flow-through basis and the recording of federal income tax adjustments, partially offset by a decrease in pretax book income.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES				
Electricity, Transmission and Distribution	$736.0	$864.4	$2,127.8	$2,349.2
Sales to AEP Affiliates	4.6	5.5	19.4	11.7
Other Revenues	1.4	1.4	4.8	4.8
TOTAL REVENUES	742.0	871.3	2,152.0	2,365.7
EXPENSES				
Purchased Electricity for Resale	180.7	203.4	525.4	516.1
Purchased Electricity from AEP Affiliates	26.7	35.9	83.4	121.4
Amortization of Generation Deferrals	58.7	66.1	172.9	173.0
Other Operation	125.8	184.2	377.6	525.9
Maintenance	37.9	38.8	108.4	104.4
Depreciation and Amortization	57.3	69.4	165.7	189.0
Taxes Other Than Income Taxes	100.4	101.9	293.8	291.7
TOTAL EXPENSES	587.5	699.7	1,727.2	1,921.5
OPERATING INCOME	154.5	171.6	424.8	444.2
Other Income (Expense):				
Interest Income	0.7	0.7	4.0	3.0
Carrying Costs Income	0.5	0.9	3.0	4.0
Allowance for Equity Funds Used During Construction	0.9	0.3	4.1	3.7
Interest Expense	(25.7)	(27.2)	(76.8)	(87.7)
INCOME BEFORE INCOME TAX EXPENSE	130.9	146.3	359.1	367.2
Income Tax Expense	48.3	46.4	128.0	122.5
NET INCOME	$82.6	$99.9	$231.1	$244.7

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 118.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$82.6	$99.9	$231.1	$244.7
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.4) and $(0.5) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.3)	(0.2)	(0.8)	(1.0)
TOTAL COMPREHENSIVE INCOME	$82.3	$99.7	$230.3	$243.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 321.2	$ 838.8	$ 822.3	$ 4.3	$ 1,986.6
Common Stock Dividends			(150.0)		(150.0)
Net Income			244.7		244.7
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 321.2	$ 838.8	$ 917.0	$ 3.3	$ 2,080.3
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 321.2	$ 838.8	$ 954.5	$ 3.0	$ 2,117.5
Common Stock Dividends			(130.0)		(130.0)
Net Income			231.1		231.1
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 321.2	$ 838.8	$ 1,055.6	$ 2.2	$ 2,217.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$3.1	$ 3.1
Restricted Cash for Securitized Funding	15.6	27.2
Advances to Affiliates	—	24.2
Accounts Receivable:		
Customers	27.1	51.1
Affiliated Companies	72.0	66.3
Accrued Unbilled Revenues	24.2	21.0
Miscellaneous	1.1	0.9
Allowance for Uncollectible Accounts	(0.4)	(0.4)
Total Accounts Receivable	124.0	138.9
Materials and Supplies	42.8	45.9
Emission Allowances	23.6	20.4
Risk Management Assets	0.2	0.2
Accrued Tax Benefits	15.4	0.1
Prepayments and Other Current Assets	28.1	10.9
TOTAL CURRENT ASSETS	252.8	270.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,349.5	2,319.2
Distribution	4,575.0	4,457.2
Other Property, Plant and Equipment	487.9	443.7
Construction Work in Progress	350.7	221.5
Total Property, Plant and Equipment	7,763.1	7,441.6
Accumulated Depreciation and Amortization	2,182.8	2,116.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,580.3	5,325.6
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32.3	32.3
Regulatory Assets	1,014.7	1,107.5
Securitized Assets	43.7	62.1
Deferred Charges and Other Noncurrent Assets	131.2	295.5
TOTAL OTHER NONCURRENT ASSETS	1,221.9	1,497.4
TOTAL ASSETS	$7,055.0	$ 7,093.9

See
Condensed
Notes to
Condensed

Financial Statements of Registrants beginning on page 118.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Advances from Affiliates	$ 167.6	$ —
Accounts Payable:		
General	157.8	175.4
Affiliated Companies	95.3	95.6
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2017 and December 31, 2016 Amounts Include $47 and $46.3, Respectively, Related to Ohio Phase-in-Recovery Funding)	397.0	46.4
Risk Management Liabilities	7.6	5.9
Customer Deposits	62.9	71.0
Accrued Taxes	251.3	520.3
Accrued Interest	38.3	31.2
Other Current Liabilities	166.3	236.0
TOTAL CURRENT LIABILITIES	1,344.1	1,181.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2017 and December 31, 2016 Amounts Include $47.5 and $93.9, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,321.9	1,717.5
Long-term Risk Management Liabilities	130.9	113.1
Deferred Income Taxes	1,460.7	1,346.1
Regulatory Liabilities and Deferred Investment Tax Credits	519.3	506.2
Employee Benefits and Pension Obligations	19.3	27.8
Deferred Credits and Other Noncurrent Liabilities	41.0	83.9
TOTAL NONCURRENT LIABILITIES	3,493.1	3,794.6
TOTAL LIABILITIES	4,837.2	4,976.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,055.6	954.5
Accumulated Other Comprehensive Income (Loss)	2.2	3.0
TOTAL COMMON SHAREHOLDER'S EQUITY	2,217.8	2,117.5

TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,055.0	$ 7,093.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net Income	$231.1	$244.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	165.7	189.0
Amortization of Generation Deferrals	172.9	173.0
Deferred Income Taxes	117.5	28.6
Carrying Costs Income	(3.0)	(4.0)
Allowance for Equity Funds Used During Construction	(4.1)	(3.7)
Mark-to-Market of Risk Management Contracts	19.5	124.7
Pension Contributions to Qualified Plan Trust	(8.2)	(7.1)
Property Taxes	175.9	169.1
Provision for Refund – Global Settlement, Net	(93.3)	—
Change in Other Noncurrent Assets	(126.7)	(124.9)
Change in Other Noncurrent Liabilities	43.4	17.2
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	14.9	8.8
Materials and Supplies	(7.1)	0.5
Accounts Payable	(31.2)	2.0
Accrued Taxes, Net	(284.3)	(291.1)
Other Current Assets	(17.3)	(5.7)
Other Current Liabilities	(34.8)	(46.8)
Net Cash Flows from Operating Activities	330.9	474.3
INVESTING ACTIVITIES		
Construction Expenditures	(362.5)	(276.4)
Change in Restricted Cash for Securitized Funding	11.6	11.6
Change in Advances to Affiliates, Net	24.2	330.9
Other Investing Activities	6.9	9.0
Net Cash Flows from (Used for) Investing Activities	(319.8)	75.1
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	167.6	—
Retirement of Long-term Debt – Nonaffiliated	(46.4)	(395.9)
Principal Payments for Capital Lease Obligations	(3.1)	(3.1)
Dividends Paid on Common Stock	(130.0)	(150.0)
Other Financing Activities	0.8	0.5
Net Cash Flows Used for Financing Activities	(11.1)	(548.5)
Net Increase in Cash and Cash Equivalents	—	0.9
Cash and Cash Equivalents at Beginning of Period	3.1	3.1

Cash and Cash Equivalents at End of Period	$3.1	$4.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$68.1	$78.2
Net Cash Paid for Income Taxes	69.6	178.0
Noncash Acquisitions Under Capital Leases	3.6	2.4
Construction Expenditures Included in Current Liabilities as of September 30,	56.8	30.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	1,992	2,184	4,662	4,925
Commercial	1,488	1,529	3,926	4,001
Industrial	1,472	1,494	4,249	4,162
Miscellaneous	353	369	942	955
Total Retail	5,305	5,576	13,779	14,043
Wholesale	82	113	309	226
Total KWhs	5,387	5,689	14,088	14,269

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	682	782
Normal - Heating (b)	1	1	1,104	1,105
Actual - Cooling (c)	1,313	1,535	2,001	2,247
Normal - Cooling (b)	1,395	1,390	2,064	2,055

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

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Net Income
(in millions)

Third Quarter of 2016	$52.8
Changes in Gross Margin:	
Retail Margins (a)	(15.6)
Off-system Sales	(0.7)
Transmission Revenues	4.1
Other Revenues	(2.0)
Total Change in Gross Margin	(14.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	(2.2)
Depreciation and Amortization	5.5
Taxes Other Than Income Taxes	(0.7)
Interest Income	(0.2)
Allowance for Equity Funds Used During Construction	(1.1)
Interest Expense	1.7
Total Change in Expenses and Other	3.0
Income Tax Expense	4.6
Third Quarter of 2017	$46.2

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

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

- Retail Margins decreased $16 million primarily due to the following:
  - A $17 million decrease primarily due to higher rates implemented in 2016 associated with interim rates.
  - An $11 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days.

  These decreases were partially offset by:
  - A $14 million increase due to weather-normalized margins.
- Transmission Revenues increased $4 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016.

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

- Depreciation and Amortization expenses decreased $6 million primarily due the following:
  - A $9 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates.

  This decrease was partially offset by:
  - A $4 million increase primarily related to new depreciation rates implemented in 2017 and a higher depreciable base.

• Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income.

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Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Net Income
(in millions)

Nine Months Ended September 30, 2016	$97.4
Changes in Gross Margin:	
Retail Margins (a)	(17.6)
Off-system Sales	(0.9)
Transmission Revenues	4.8
Other Revenues	(4.6)
Total Change in Gross Margin	(18.3)
Changes in Expenses and Other:	
Other Operation and Maintenance	(31.1)
Depreciation and Amortization	12.1
Taxes Other Than Income Taxes	(2.2)
Interest Income	(0.4)
Allowance for Equity Funds Used During Construction	(4.5)
Interest Expense	4.4
Total Change in Expenses and Other	(21.7)
Income Tax Expense	14.0
Nine Months Ended September 30, 2017	$71.4

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

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

- Retail Margins decreased $18 million primarily due to the following:
- A $15 million decrease in weather-related usage primarily due to an 11% decrease in cooling degree days and a 13% decrease in heating degree days.
- A $14 million decrease primarily due to higher rates implemented in 2016 associated with interim rates.

These decreases were partially offset by:

- A $9 million increase primarily due to higher weather-normalized margins.
- A $5 million increase related to new base rates implemented in January 2017.
- Transmission Revenues increased $5 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016 and additional transmission investments in SPP.
- Other Revenues decreased $5 million primarily due to the elimination of connection charges for certain customers with advanced metering, effective with the implementation of new base rates in January 2017.

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

- Other Operation and Maintenance expenses increased $31 million primarily due to the following:
  - A $16 million increase in vegetation management expenses. This increase is partially offset by a corresponding increase in Retail Margins as vegetation management expenses recovered in the prior year under the System Reliability Rider are now recovered as a component of base rates in the current year.
  - A $15 million increase in transmission expenses primarily due to increased SPP transmission services.
- Depreciation and Amortization expenses decreased $12 million primarily due the following:
  - A $24 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates.

  This decrease was partially offset by:
  - A $12 million increase primarily related to new depreciation rates implemented in 2017 and a higher depreciable base.
- Allowance for Equity Funds Used During Construction decreased $5 million primarily due to the completion of environmental projects.
- Interest Expense decreased $4 million primarily due to the deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and the Comanche Plant.
- Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$440.6	$400.9	$1,085.1	$971.3
Sales to AEP Affiliates	1.1	0.1	3.2	2.0
Other Revenues	1.1	0.7	3.3	2.9
TOTAL REVENUES	442.8	401.7	1,091.6	976.2
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	77.9	16.4	115.8	43.0
Purchased Electricity for Resale	127.8	130.8	379.8	315.3
Purchased Electricity from AEP Affiliates	—	3.2	—	3.6
Other Operation	83.6	81.0	226.3	211.8
Maintenance	25.2	25.6	88.2	71.6
Depreciation and Amortization	31.7	37.2	97.8	109.9
Taxes Other Than Income Taxes	9.8	9.1	30.0	27.8
TOTAL EXPENSES	356.0	303.3	937.9	783.0
OPERATING INCOME	86.8	98.4	153.7	193.2
Other Income (Expense):				
Interest Income	—	0.2	0.1	0.5
Allowance for Equity Funds Used During Construction	—	1.1	0.4	4.9
Interest Expense	(13.2)	(14.9)	(40.2)	(44.6)
INCOME BEFORE INCOME TAX EXPENSE	73.6	84.8	114.0	154.0
Income Tax Expense	27.4	32.0	42.6	56.6
NET INCOME	$46.2	$52.8	$71.4	$97.4

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

See Condensed Notes to Condensed Financial

Statements of
Registrants
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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$46.2	$52.8	$71.4	$97.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.2)	(0.2)	(0.6)	(0.6)
TOTAL COMPREHENSIVE INCOME	$46.0	$52.6	$70.8	$96.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 157.2	$ 364.0	$ 594.5	$ 4.2	$ 1,119.9
Net Income			97.4		97.4
Other Comprehensive Loss				(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 157.2	$ 364.0	$ 691.9	$ 3.6	$ 1,216.7
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	$ 157.2	$ 364.0	$ 689.5	$ 3.4	$ 1,214.1
Common Stock Dividends			(52.5)		(52.5)
Net Income			71.4		71.4
Other Comprehensive Loss				(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2017	$ 157.2	$ 364.0	$ 708.4	$ 2.8	$ 1,232.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$2.1	$ 1.5
Accounts Receivable:		
Customers	17.8	27.5
Affiliated Companies	31.8	26.8
Miscellaneous	3.2	4.4
Allowance for Uncollectible Accounts	(0.1)	(0.2)
Total Accounts Receivable	52.7	58.5
Fuel	11.9	22.9
Materials and Supplies	42.1	44.6
Risk Management Assets	4.7	0.8
Accrued Tax Benefits	27.0	27.3
Regulatory Asset for Under-Recovered Fuel Costs	36.9	33.8
Prepayments and Other Current Assets	14.4	6.0
TOTAL CURRENT ASSETS	191.8	195.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,573.8	1,559.3
Transmission	852.5	832.8
Distribution	2,414.1	2,322.4
Other Property, Plant and Equipment	286.3	233.2
Construction Work in Progress	114.0	148.2
Total Property, Plant and Equipment	5,240.7	5,095.9
Accumulated Depreciation and Amortization	1,382.8	1,272.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,857.9	3,823.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	393.6	340.2
Employee Benefits and Pension Assets	16.0	10.4
Deferred Charges and Other Noncurrent Assets	19.2	10.0
TOTAL OTHER NONCURRENT ASSETS	428.8	360.6
TOTAL ASSETS	$4,478.5	$ 4,379.2

See Condensed Notes to Condensed Financial Statements

of
Registrants
beginning
on page
118.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2017 and December 31, 2016
(Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$118.0	$ 52.0
Accounts Payable:		
General	93.8	116.3
Affiliated Companies	43.0	56.2
Long-term Debt Due Within One Year – Nonaffiliated	0.5	0.5
Customer Deposits	53.1	49.7
Accrued Taxes	40.8	21.0
Accrued Interest	19.5	13.9
Provision for Refund	4.1	46.1
Other Current Liabilities	38.5	47.8
TOTAL CURRENT LIABILITIES	411.3	403.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,285.9	1,285.5
Deferred Income Taxes	1,152.5	1,058.8
Regulatory Liabilities and Deferred Investment Tax Credits	320.9	339.7
Asset Retirement Obligations	54.5	52.8
Deferred Credits and Other Noncurrent Liabilities	21.0	24.8
TOTAL NONCURRENT LIABILITIES	2,834.8	2,761.6
TOTAL LIABILITIES	3,246.1	3,165.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	708.4	689.5
Accumulated Other Comprehensive Income (Loss)	2.8	3.4
TOTAL COMMON SHAREHOLDER'S EQUITY	1,232.4	1,214.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,478.5	$ 4,379.2

See
Condensed
Notes to

Condensed Financial Statements of Registrants beginning on page 118.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30,					
	2017			2016		
OPERATING ACTIVITIES						
Net Income	$	71.4		$	97.4	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	97.8			109.9		
Deferred Income Taxes	93.7			79.5		
Allowance for Equity Funds Used During Construction	(0.4		)	(4.9		)
Mark-to-Market of Risk Management Contracts	(3.9		)	(0.7		)
Pension Contributions to Qualified Plan Trust	(5.3		)	(5.6		)
Property Taxes	(9.4		)	(8.0		)
Deferred Fuel Over/Under-Recovery, Net	(5.6		)	(80.2		)
Provision for Refund, Net	(39.4		)	13.8		
Change in Other Noncurrent Assets	(19.8		)	(18.8		)
Change in Other Noncurrent Liabilities	(1.4		)	(3.7		)
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	5.8			4.4		
Fuel, Materials and Supplies	13.5			(2.4		)
Accounts Payable	(18.5		)	23.1		
Accrued Taxes, Net	20.1			45.4		
Other Current Assets	(8.2		)	(2.2		)
Other Current Liabilities	1.5			(14.9		)
Net Cash Flows from Operating Activities	191.9			232.1		
INVESTING ACTIVITIES						
Construction Expenditures	(203.1		)	(266.8		)
Change in Advances to Affiliates, Net	—			29.5		
Other Investing Activities	1.5			8.7		
Net Cash Flows Used for Investing Activities	(201.6		)	(228.6		)

FINANCING ACTIVITIES				
Issuance of Long-term Debt – Nonaffiliated	—		150.0	
Change in Advances from Affiliates, Net	66.0		—	
Retirement of Long-term Debt – Nonaffiliated	(0.3	)	(150.3	)
Principal Payments for Capital Lease Obligations	(3.2	)	(3.0	)
Dividends Paid on Common Stock	(52.5	)	—	
Other Financing Activities	0.3		0.4	
Net Cash Flows from (Used for) Financing Activities	10.3		(2.9	)
Net Increase in Cash and Cash Equivalents	0.6		0.6	
Cash and Cash Equivalents at Beginning of Period	1.5		1.4	
Cash and Cash Equivalents at End of Period	$ 2.1		$ 2.0	
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$ 40.9		$ 45.0	
Net Cash Paid (Received) for Income Taxes	(46.6	)	(50.3	)
Noncash Acquisitions Under Capital Leases	1.0		2.2	
Construction Expenditures Included in Current Liabilities as of September 30,	15.1		20.2	

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions of KWhs)			
Retail:				
Residential	1,887	2,105	4,547	4,879
Commercial	1,677	1,793	4,466	4,652
Industrial	1,339	1,254	3,895	3,830
Miscellaneous	19	20	60	61
Total Retail	4,922	5,172	12,968	13,422
Wholesale	2,105	2,326	6,286	6,056
Total KWhs	7,027	7,498	19,254	19,478

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Actual - Heating (a)	—	—	394	586
Normal - Heating (b)	1	1	747	747
Actual - Cooling (c)	1,248	1,502	1,999	2,277
Normal - Cooling (b)	1,414	1,410	2,185	2,177

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

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2016	$83.3
Changes in Gross Margin:	
Retail Margins (a)	(6.9)
Off-system Sales	0.1
Transmission Revenues	(8.0)
Other Revenues	(0.1)
Total Change in Gross Margin	(14.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	10.1
Depreciation and Amortization	(4.0)
Taxes Other Than Income Taxes	(1.6)
Interest Income	0.7
Allowance for Equity Funds Used During Construction	0.3
Interest Expense	0.7
Total Change in Expenses and Other	6.2
Income Tax Expense	10.7
Equity Earnings (Loss) of Unconsolidated Subsidiary	(2.3)
Net Income Attributable to Noncontrolling Interest	(9.9)
Third Quarter of 2017	$73.1

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

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

- Retail Margins decreased $7 million primarily due to the following:
  - An $18 million decrease in weather-related usage due to a 17% decrease in cooling degree days.

  This decrease was partially offset by:
  - An $11 million increase due to rider revenue increases in Louisiana, partially offset in expense items below.
- Transmission Revenues decreased $8 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is offset by a corresponding decrease in Other Operation and Maintenance expenses below.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses decreased $10 million primarily due to a $12 million accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is partially offset by a corresponding decrease in Transmission Revenues above.

- Depreciation and Amortization expenses increased $4 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $11 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This decrease is offset by an increase in Net Income Attributable to Noncontrolling Interest below.
- Net Income Attributable to Noncontrolling Interest increased $10 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense above.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to Nine Months Ended September 30, 2017
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2016	$ 149.9
Changes in Gross Margin:	
Retail Margins (a)	(8.4)
Off-system Sales	3.8
Transmission Revenues	(5.5)
Other Revenues	0.3
Total Change in Gross Margin	(9.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	6.6
Depreciation and Amortization	(10.0)
Taxes Other Than Income Taxes	(5.8)
Interest Income	2.0
Allowance For Equity Funds Used During Construction	(8.3)
Interest Expense	(0.7)
Total Change in Expenses and Other	(16.2)
Income Tax Expense	8.7
Equity Earnings (Loss) of Unconsolidated Subsidiary	(9.4)
Net Income Attributable to Noncontrolling Interest	(9.3)
Nine Months Ended September 30, 2017	$ 113.9

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

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

- Retail Margins decreased $8 million primarily due to the following:
- A $29 million decrease in weather-related usage primarily due to a 33% decrease in heating degree days and a 12% decrease in cooling degree days.
- A $9 million decrease in FERC generation wholesale municipal and cooperative revenues due to an annual formula rate true-up.
- A $3 million decrease primarily due to lower fuel cost recovery.

These decreases were partially offset by:

- A $33 million increase due to rider revenue increases in Louisiana, Texas and Arkansas, partially offset in various expenses below.
- Margins from Off-System Sales increased $4 million primarily due to higher sales prices.
- Transmission Revenues decreased $6 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is offset by a corresponding decrease in Other Operation and Maintenance expenses below.

Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiary and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses decreased $7 million primarily due to an accrual for SPP sponsor-funded transmission upgrades in third quarter 2016. This decrease is partially offset by a corresponding decrease in Transmission Revenues above.
- Depreciation and Amortization expenses increased $10 million primarily due to a higher depreciable base.
- Taxes Other than Income Taxes increased $6 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction decreased $8 million primarily due to the completion of environmental projects.
- Income Tax Expense decreased $9 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This decrease is offset by an increase in Net Income Attributable to Noncontrolling Interest below.
- Equity Earnings (Loss) of Unconsolidated Subsidiary decreased $9 million primarily due to a prior period income tax adjustment for DHLC.
- Net Income Attributable to Noncontrolling Interest increased $9 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES				
Electric Generation, Transmission and Distribution	$509.5	$530.5	$1,321.8	$1,324.1
Sales to AEP Affiliates	7.7	8.6	20.4	20.0
Other Revenues	0.4	0.6	1.4	1.6
TOTAL REVENUES	517.6	539.7	1,343.6	1,345.7
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	147.5	158.8	389.8	403.3
Purchased Electricity for Resale	40.0	35.9	118.7	97.5
Other Operation	80.3	89.2	232.2	243.3
Maintenance	32.6	33.8	106.5	102.0
Depreciation and Amortization	55.2	51.2	158.1	148.1
Taxes Other Than Income Taxes	25.0	23.4	72.6	66.8
TOTAL EXPENSES	380.6	392.3	1,077.9	1,061.0
OPERATING INCOME	137.0	147.4	265.7	284.7
Other Income (Expense):				
Interest Income	0.7	—	2.0	—
Allowance for Equity Funds Used During Construction	0.4	0.1	1.2	9.5
Interest Expense	(31.9)	(32.6)	(92.7)	(92.0)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	106.2	114.9	176.2	202.2
Income Tax Expense	22.5	33.2	45.2	53.9
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.4	2.7	(4.5)	4.9
NET INCOME	84.1	84.4	126.5	153.2
Net Income Attributable to Noncontrolling Interest	11.0	1.1	12.6	3.3
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$73.1	$83.3	$113.9	$149.9

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income	$84.1	$84.4	$126.5	$153.2
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.2 and $0.2 for the Three Months Ended September 30, 2017 and 2016, Respectively, and $0.6 and $0.7 for the Nine Months Ended September 30, 2017 and 2016, Respectively	0.4	0.4	1.1	1.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2017 and 2016, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2017 and 2016, Respectively	(0.2)	(0.1)	(0.5)	(0.5)
TOTAL OTHER COMPREHENSIVE INCOME	0.2	0.3	0.6	0.8
TOTAL COMPREHENSIVE INCOME	84.3	84.7	127.1	154.0
Total Comprehensive Income Attributable to Noncontrolling Interest	11.0	1.1	12.6	3.3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$73.3	$83.6	$114.5	$150.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY - DECEMBER 31, 2015	$135.7	$676.6	$1,366.3	$ (9.4)	$ 0.5	$2,169.7
Common Stock Dividends			(90.0)			(90.0)
Common Stock Dividends – Nonaffiliated					(3.5)	(3.5)
Net Income			149.9		3.3	153.2
Other Comprehensive Income				0.8		0.8
TOTAL EQUITY - SEPTEMBER 30, 2016	$135.7	$676.6	$1,426.2	$ (8.6)	$ 0.3	$2,230.2
TOTAL EQUITY - DECEMBER 31, 2016	$135.7	$676.6	$1,411.9	$ (9.4)	$ 0.4	$2,215.2
Common Stock Dividends			(82.5)			(82.5)
Common Stock Dividends – Nonaffiliated					(2.7)	(2.7)
Net Income			113.9		12.6	126.5
Other Comprehensive Income				0.6		0.6
TOTAL EQUITY - SEPTEMBER 30, 2017	$135.7	$676.6	$1,443.3	$ (8.8)	$ 10.3	$2,257.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2017 and December 31, 2016
(in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents		
(September 30, 2017 and December 31, 2016 Amounts Include $0 and $8.7, Respectively, Related to Sabine)	$ 2.2	$ 10.3
Advances to Affiliates	2.0	169.8
Accounts Receivable:		
Customers	23.5	48.5
Affiliated Companies	37.6	29.3
Miscellaneous	20.8	17.5
Allowance for Uncollectible Accounts	(1.5)	(1.2)
Total Accounts Receivable	80.4	94.1
Fuel		
(September 30, 2017 and December 31, 2016 Amounts Include $43.2 and $34.3, Respectively, Related to Sabine)	93.1	107.1
Materials and Supplies	68.8	68.4
Risk Management Assets	12.5	0.9
Accrued Tax Benefits	14.5	51.5
Regulatory Asset for Under-Recovered Fuel Costs	13.6	8.4
Prepayments and Other Current Assets	35.5	35.5
TOTAL CURRENT ASSETS	322.6	546.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,632.9	4,607.6
Transmission	1,656.4	1,584.2
Distribution	2,084.2	2,020.6
Other Property, Plant and Equipment		
(September 30, 2017 and December 31, 2016 Amounts Include $266.6 and $267.5, Respectively, Related to Sabine)	701.6	670.4
Construction Work in Progress	145.2	113.8
Total Property, Plant and Equipment	9,220.3	8,996.6
Accumulated Depreciation and Amortization		
(September 30, 2017 and December 31, 2016 Amounts Include $162.8 and $155.6, Respectively, Related to Sabine)	2,670.5	2,567.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,549.8	6,429.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	566.4	551.2
Long-term Risk Management Assets	0.7	—
Deferred Charges and Other Noncurrent Assets	116.4	99.9

TOTAL OTHER NONCURRENT ASSETS	683.5	651.1
TOTAL ASSETS	$7,555.9	$ 7,626.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2017 and December 31, 2016
(Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$48.3	$ —
Accounts Payable:		
General	120.9	117.5
Affiliated Companies	38.5	68.5
Short-term Debt – Nonaffiliated	14.3	—
Long-term Debt Due Within One Year – Nonaffiliated	385.4	353.7
Risk Management Liabilities	0.1	0.3
Customer Deposits	61.6	62.1
Accrued Taxes	73.0	40.9
Accrued Interest	25.1	45.1
Obligations Under Capital Leases	11.4	11.8
Other Current Liabilities	77.5	83.9
TOTAL CURRENT LIABILITIES	856.1	783.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,056.1	2,325.4
Deferred Income Taxes	1,694.5	1,606.9
Regulatory Liabilities and Deferred Investment Tax Credits	441.3	438.9
Asset Retirement Obligations	159.0	147.1
Employee Benefits and Pension Obligations	19.9	34.1
Obligations Under Capital Leases	60.2	65.5
Deferred Credits and Other Noncurrent Liabilities	11.7	9.7
TOTAL NONCURRENT LIABILITIES	4,442.7	4,627.6
TOTAL LIABILITIES	5,298.8	5,411.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135.7	135.7
Paid-in Capital	676.6	676.6
Retained Earnings	1,443.3	1,411.9
Accumulated Other Comprehensive Income (Loss)	(8.8)	(9.4)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,246.8	2,214.8
Noncontrolling Interest	10.3	0.4

TOTAL EQUITY	2,257.1	2,215.2
TOTAL LIABILITIES AND EQUITY	$7,555.9	$ 7,626.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2017 and 2016
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2017			2016		
OPERATING ACTIVITIES						
Net Income	$	126.5		$	153.2	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	158.1			148.1		
Deferred Income Taxes	79.8			141.9		
Allowance for Equity Funds Used During Construction	(1.2		)	(9.5		)
Mark-to-Market of Risk Management Contracts	(12.5		)	(5.8		)
Pension Contributions to Qualified Plan Trust	(8.9		)	(8.3		)
Property Taxes	(15.4		)	(13.7		)
Deferred Fuel Over/Under-Recovery, Net	2.4			1.2		
Change in Other Noncurrent Assets	(2.9		)	18.4		
Change in Other Noncurrent Liabilities	(5.2		)	(25.8		)
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	12.1			12.2		
Fuel, Materials and Supplies	13.6			33.4		
Accounts Payable	(25.7		)	(17.2		)
Accrued Taxes, Net	69.1			14.1		
Accrued Interest	(20.0		)	(20.0		)
Other Current Assets	0.7			(2.4		)
Other Current Liabilities	(14.6		)	(24.8		)
Net Cash Flows from Operating Activities	355.9			395.0		
INVESTING ACTIVITIES						
Construction Expenditures	(265.3		)	(315.3		)
Change in Advances to Affiliates, Net	167.8			(297.4		)
Other Investing Activities	3.1			(1.9		)
Net Cash Flows Used for Investing Activities	(94.4		)	(614.6		)

FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	114.6	402.2
Change in Short-term Debt – Nonaffiliated	14.3	—
Change in Advances from Affiliates, Net	48.3	(58.3)
Retirement of Long-term Debt – Nonaffiliated	(353.6)	(3.3)
Principal Payments for Capital Lease Obligations	(8.4)	(18.6)
Dividends Paid on Common Stock	(82.5)	(90.0)
Dividends Paid on Common Stock – Nonaffiliated	(2.7)	(3.5)
Other Financing Activities	0.4	1.1
Net Cash Flows from (Used for) Financing Activities	(269.6)	229.6
Net Increase (Decrease) in Cash and Cash Equivalents	(8.1)	10.0
Cash and Cash Equivalents at Beginning of Period	10.3	5.2
Cash and Cash Equivalents at End of Period	$ 2.2	$ 15.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 109.4	$ 107.6
Net Cash Paid (Received) for Income Taxes	(70.5)	(66.6)
Noncash Acquisitions Under Capital Leases	2.8	5.5
Construction Expenditures Included in Current Liabilities as of September 30,	40.7	54.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 118.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

The condensed notes to condensed 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:

Note	Registrant	Page Number
Significant Accounting Matters	AEP, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	119
New Accounting Pronouncements	AEP, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	121
Comprehensive Income	AEP, APCo, I&M, OPCo, PSO, SWEPCo	124
Rate Matters	AEP, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	136
Commitments, Guarantees and Contingencies	AEP, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	146
Impairment, Disposition, and Assets and Liabilities Held for Sale	AEP, I&M	152
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1. SIGNIFICANT ACCOUNTING MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and nine months ended September 30, 2017 is not necessarily indicative of results that may be expected for the year ending December 31, 2017. The condensed financial statements are unaudited and should be read in conjunction with the audited 2016 financial statements and notes thereto, which are included in the Registrants (except AEPTCo) Annual Reports on Form 10-K as filed with the SEC on February 27, 2017. AEPTCo should be read in conjunction with the audited 2016 financial statements and notes thereto, which are included on Form S-4 as filed with the SEC on April 5, 2017.

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 tables present AEP's basic and diluted EPS calculations included on the statements of income:

	Three Months Ended September 30,			
	2017		2016	
	(in millions, except per share data)			
		$/share		$/share
Income (Loss) from Continuing Operations	$556.7		$(764.2)	
Less: Net Income Attributable to Noncontrolling Interests	12.0		1.6	
Earnings (Loss) Attributable to AEP Common Shareholders from Continuing Operations	$544.7		$(765.8)	
Weighted Average Number of Basic Shares Outstanding	491.8	$1.11	491.7	$(1.56)
Weighted Average Dilutive Effect of Stock-Based Awards	1.2	(0.01)	0.1	—
Weighted Average Number of Diluted Shares Outstanding	493.0	$1.10	491.8	$(1.56)

	Nine Months Ended September 30,			
	2017		2016	
	(in millions, except per share data)			
		$/share		$/share
Income from Continuing Operations	$1,527.1		$245.3	
Less: Net Income Attributable to Noncontrolling Interests	15.2		5.3	

Earnings Attributable to AEP Common Shareholders from Continuing Operations	$1,511.9		$240.0	
Weighted Average Number of Basic Shares Outstanding	491.8	$ 3.07	491.4	$ 0.49
Weighted Average Dilutive Effect of Stock-Based Awards	0.6	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	492.4	$ 3.07	491.6	$ 0.49

There were no antidilutive shares outstanding as of September 30, 2017 and 2016.

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Nonconsolidated Variable Interest Entity (Applies to AEP and SWEPCo)

SWEPCo recorded prior year income tax adjustments in the second quarter of 2017 related to DHLC that impacted Equity Earnings (Loss) of Unconsolidated Subsidiary in the amount of $6 million.

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Nine Months Ended September 30, 2017	2016
	(in millions)	
Cash Paid (Received) for:		
Interest, Net of Capitalized Amounts	$613.8	$637.0
Income Taxes, Net	(6.8)	32.2
Noncash Investing and Financing Activities:		
Acquisitions Under Capital Leases	44.5	65.8
Construction Expenditures Included in Current Liabilities as of September 30,	791.6	604.8
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	71.8	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.6	0.3
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.8	—

2. NEW ACCOUNTING PRONOUNCEMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following final 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 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted.

Management continues to analyze 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. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption.

The evaluation of revenue streams, new contracts and the new revenue standard's disclosure requirements continues during the fourth quarter of 2017, in particular with respect to various ongoing industry implementation issues. Management will continue to analyze the related impacts to revenue recognition and monitor any new industry implementation issues that arise. Further, given industry conclusions related to implementation issues, including contributions in aid of construction and collectability, management does not anticipate changes to current accounting systems. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance 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. The amendments will be applied by means of a cumulative-effect adjustment to the balance

sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

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.

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, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. 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 current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

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. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

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 2016, AEP's actual non-service cost components were a credit of $66 million, of which approximately 37% 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 plans to adopt 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 net income.

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 condensed financial statements.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three and nine months ended September 30, 2017 and 2016. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of June 30, 2017	$(36.0)	$(10.4)	$ 10.2	$(125.4)	$(161.6)
Change in Fair Value Recognized in AOCI	(15.8)	(2.0)	0.9	—	(16.9)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(0.9)	—	—	—	(0.9)
Purchased Electricity for Resale	4.9	—	—	—	4.9
Interest Expense	—	0.4	—	—	0.4
Amortization of Prior Service Cost (Credit)	—	—	—	(5.0)	(5.0)
Amortization of Actuarial (Gains)/Losses	—	—	—	5.4	5.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	4.0	0.4	—	0.4	4.8
Income Tax (Expense) Credit	1.4	0.2	—	0.1	1.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2.6	0.2	—	0.3	3.1
Net Current Period Other Comprehensive Income (Loss)	(13.2)	(1.8)	0.9	0.3	(13.8)
Balance in AOCI as of September 30, 2017	$(49.2)	$(12.2)	$ 11.1	$(125.1)	$(175.4)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of June 30, 2016	$1.9	$(16.5)	$ 8.3	$(111.6)	$(117.9)
Change in Fair Value Recognized in AOCI	(26.7)	—	0.5	—	(26.2)
Amount of (Gain) Loss Reclassified from AOCI					

Generation & Marketing Revenues	(5.4)	—	—	—	(5.4)
Purchased Electricity for Resale	1.8	—	—	—	1.8
Interest Expense	—	0.6	—	—	0.6
Amortization of Prior Service Cost (Credit)	—	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains)/Losses	—	—	—	5.0	5.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	(3.6)	0.6	—	0.2	(2.8)
Income Tax (Expense) Credit	(1.3)	0.2	—	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(2.3)	0.4	—	0.2	(1.7)
Net Current Period Other Comprehensive Income (Loss)	(29.0)	0.4	0.5	0.2	(27.9)
Balance in AOCI as of September 30, 2016	$(27.1)	$(16.1)	$ 8.8	$(111.4)	$(145.8)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2016	$(23.1)	$(15.7)	$ 8.4	$(125.9)	$(156.3)
Change in Fair Value Recognized in AOCI	(39.4)	2.7	2.7	—	(34.0)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(5.6)	—	—	—	(5.6)
Purchased Electricity for Resale	26.0	—	—	—	26.0
Interest Expense	—	1.2	—	—	1.2
Amortization of Prior Service Cost (Credit)	—	—	—	(14.8)	(14.8)
Amortization of Actuarial (Gains)/Losses	—	—	—	16.0	16.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	20.4	1.2	—	1.2	22.8
Income Tax (Expense) Credit	7.1	0.4	—	0.4	7.9
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	13.3	0.8	—	0.8	14.9
Net Current Period Other Comprehensive Income (Loss)	(26.1)	3.5	2.7	0.8	(19.1)
Balance in AOCI as of September 30, 2017	$(49.2)	$(12.2)	$ 11.1	$(125.1)	$(175.4)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2015	$(5.2)	$(17.2)	$ 7.1	$(111.8)	$(127.1)
Change in Fair Value Recognized in AOCI	(17.7)	—	1.7	—	(16.0)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(20.7)	—	—	—	(20.7)
Purchased Electricity for Resale	14.2	—	—	—	14.2
Interest Expense	—	1.7	—	—	1.7
Amortization of Prior Service Cost (Credit)	—	—	—	(14.6)	(14.6)
Amortization of Actuarial (Gains)/Losses	—	—	—	15.2	15.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(6.5)	1.7	—	0.6	(4.2)
Income Tax (Expense) Credit	(2.3)	0.6	—	0.2	(1.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(4.2)	1.1	—	0.4	(2.7)
Net Current Period Other Comprehensive Income (Loss)	(21.9)	1.1	1.7	0.4	(18.7)
Balance in AOCI as of September 30, 2016	$(27.1)	$(16.1)	$ 8.8	$(111.4)	$(145.8)

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APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$2.5	$(11.9)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.2)	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Amortization of Actuarial (Gains)/Losses	—	0.9	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)	(0.5)	(0.7)
Income Tax (Expense) Credit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.1)	(0.3)	(0.4)
Net Current Period Other Comprehensive Loss	(0.1)	(0.3)	(0.4)
Balance in AOCI as of September 30, 2017	$2.4	$(12.2)	$(9.8)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2016	$3.2	$(7.1)	$(3.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.2)	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	(1.2)	(1.2)
Amortization of Actuarial (Gains)/Losses	—	0.7	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)	(0.5)	(0.7)
Income Tax (Expense) Credit	—	(0.2)	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)	(0.3)	(0.5)
Net Current Period Other Comprehensive Loss	(0.2)	(0.3)	(0.5)
Balance in AOCI as of September 30, 2016	$3.0	$(7.4)	$(4.4)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$2.9	$(11.3)	$(8.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.8)	—	(0.8)
Amortization of Prior Service Cost (Credit)	—	(4.0)	(4.0)
Amortization of Actuarial (Gains)/Losses	—	2.6	2.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)	(1.4)	(2.2)
Income Tax (Expense) Credit	(0.3)	(0.5)	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.5)	(0.9)	(1.4)
Net Current Period Other Comprehensive Loss	(0.5)	(0.9)	(1.4)
Balance in AOCI as of September 30, 2017	$2.4	$(12.2)	$(9.8)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2015	$3.6	$(6.4)	$(2.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.8)	—	(0.8)
Amortization of Prior Service Cost (Credit)	—	(3.8)	(3.8)
Amortization of Actuarial (Gains)/Losses	—	2.2	2.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)	(1.6)	(2.4)
Income Tax (Expense) Credit	(0.2)	(0.6)	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.6)	(1.0)	(1.6)
Net Current Period Other Comprehensive Loss	(0.6)	(1.0)	(1.6)
Balance in AOCI as of September 30, 2016	$3.0	$(7.4)	$(4.4)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$(11.3)	$(4.2)	$(15.5)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.3)	(0.3)
Amortization of Actuarial (Gains)/Losses	—	0.3	0.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	—	0.5
Income Tax (Expense) Credit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income	0.3	—	0.3
Balance in AOCI as of September 30, 2017	$(11.0)	$(4.2)	$(15.2)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2016	$(12.6)	$(3.4)	$(16.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	—	0.5
Income Tax (Expense) Credit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income	0.3	—	0.3
Balance in AOCI as of September 30, 2016	$(12.3)	$(3.4)	$(15.7)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(12.0)	$(4.2)	$(16.2)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.7)	(0.7)
Amortization of Actuarial (Gains)/Losses	—	0.7	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.5	—	1.5
Income Tax (Expense) Credit	0.5	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.0	—	1.0
Net Current Period Other Comprehensive Income	1.0	—	1.0
Balance in AOCI as of September 30, 2017	$(11.0)	$(4.2)	$(15.2)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2015	$(13.3)	$(3.4)	$(16.7)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains)/Losses	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.5	—	1.5
Income Tax (Expense) Credit	0.5	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.0	—	1.0
Net Current Period Other Comprehensive Income	1.0	—	1.0
Balance in AOCI as of September 30, 2016	$(12.3)	$(3.4)	$(15.7)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of June 30, 2017	$ 2.5
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.5)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)
Net Current Period Other Comprehensive Loss	(0.3)
Balance in AOCI as of September 30, 2017	$ 2.2

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of June 30, 2016	$ 3.5
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Loss	(0.2)
Balance in AOCI as of September 30, 2016	$ 3.3

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedges 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	(1.3)
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 Loss	(0.8)
Balance in AOCI as of September 30, 2017	$ 2.2

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges 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	(1.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.4)
Income Tax (Expense) Credit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1.0)
Net Current Period Other Comprehensive Loss	(1.0)
Balance in AOCI as of September 30, 2016	$ 3.3

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of June 30, 2017	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Loss	(0.2)
Balance in AOCI as of September 30, 2017	$ 2.8

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges Interest Rate (in millions)
Balance in AOCI as of June 30, 2016	$ 3.8
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Loss	(0.2)
Balance in AOCI as of September 30, 2016	$ 3.6

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedges 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	(1.0)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.0)
Income Tax (Expense) Credit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.6)
Net Current Period Other Comprehensive Loss	(0.6)
Balance in AOCI as of September 30, 2017	$ 2.8

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges 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	(0.9)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.9)
Income Tax (Expense) Credit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.6)
Net Current Period Other Comprehensive Loss	(0.6)
Balance in AOCI as of September 30, 2016	$ 3.6

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2017	$(6.7)	$(2.3)	$(9.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.6	(0.3)	0.3
Income Tax (Expense) Credit	0.2	(0.1)	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	(0.2)	0.2
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.2)	0.2
Balance in AOCI as of September 30, 2017	$(6.3)	$(2.5)	$(8.8)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of June 30, 2016	$(8.2)	$(0.7)	$(8.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.7	—	0.7
Amortization of Prior Service Cost (Credit)	—	(0.4)	(0.4)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.7	(0.2)	0.5
Income Tax (Expense) Credit	0.3	(0.1)	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	(0.1)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.1)	0.3
Balance in AOCI as of September 30, 2016	$(7.8)	$(0.8)	$(8.6)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(7.4)	$(2.0)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	1.7	—	1.7
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains)/Losses	—	0.7	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.7	(0.8)	0.9
Income Tax (Expense) Credit	0.6	(0.3)	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.1	(0.5)	0.6
Net Current Period Other Comprehensive Income (Loss)	1.1	(0.5)	0.6
Balance in AOCI as of September 30, 2017	$(6.3)	$(2.5)	$(8.8)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2015	$(9.1)	$(0.3)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	2.0	—	2.0
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Amortization of Actuarial (Gains)/Losses	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	2.0	(0.8)	1.2
Income Tax (Expense) Credit	0.7	(0.3)	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1.3	(0.5)	0.8
Net Current Period Other Comprehensive Income (Loss)	1.3	(0.5)	0.8
Balance in AOCI as of September 30, 2016	$(7.8)	$(0.8)	$(8.6)

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

As discussed in AEP's and AEPTCo's 2016 Annual Reports, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within AEP's and AEPTCo's 2016 Annual Reports should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2017 and updates AEP's and AEPTCo's 2016 Annual Reports.

Regulatory Assets Pending Final Regulatory Approval

	AEP	
	September 30, 2017	December 31, 2016
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant (a)	$209.1	$ 159.9
Storm-Related Costs	97.4	25.1
Plant Retirement Costs - Materials and Supplies	9.1	9.1
Ohio Capacity Deferral	—	96.7
Other Regulatory Assets Pending Final Regulatory Approval	1.1	1.3
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	42.6	25.9
Plant Retirement Costs - Asset Retirement Obligation Costs	37.2	29.6
Cook Plant Uprate Project	36.3	36.3
Environmental Control Projects	24.3	24.1
Cook Plant Turbine	15.1	12.8
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	13.0	8.1
Other Regulatory Assets Pending Final Regulatory Approval	25.6	21.2
Total Regulatory Assets Pending Final Regulatory Approval (b)	$510.8	$ 450.1

(a) In March 2017, $41 million was reclassified from accumulated depreciation to regulatory assets related to Northeastern Plant, Unit 3. As of September 30, 2017, the unrecovered plant balance related to Northeastern Plant, Unit 3 was $52 million.

(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.

Noncurrent Regulatory Assets	APCo September 30, 2017	December 31, 2016
	(in millions)	
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	37.2	29.6
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6
Total Regulatory Assets Pending Final Regulatory Approval (a)	$46.9	$ 39.3

(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.

Noncurrent Regulatory Assets	I&M September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Uprate Project	$36.3	$ 36.3
Cook Plant Turbine	15.1	12.8
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	13.0	8.1
Rockport Dry Sorbent Injection System - Indiana	9.4	6.6
Other Regulatory Assets Pending Final Regulatory Approval	1.5	0.9
Total Regulatory Assets Pending Final Regulatory Approval	$75.3	$ 64.7

Noncurrent Regulatory Assets	OPCo September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Capacity Deferral	$—	$ 96.7
Regulatory Assets Currently Not Earning a Return		
Smart Grid Costs	—	4.1
Total Regulatory Assets Pending Final Regulatory Approval	$—	$ 100.8

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Noncurrent Regulatory Assets	PSO September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant (a)	$133.7	$ 84.5
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.5
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	36.7	20.0
Environmental Control Projects	24.3	13.1
Other Regulatory Assets Pending Final Regulatory Approval	0.4	—
Total Regulatory Assets Pending Final Regulatory Approval	$195.6	$ 118.1

(a) In March 2017, $41 million was reclassified from accumulated depreciation to regulatory assets related to Northeastern Plant, Unit 3. As of September 30, 2017, the unrecovered plant balance related to Northeastern Plant, Unit 3 was $52 million.

Noncurrent Regulatory Assets	SWEPCo September 30, 2017	December 31, 2016
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$75.4	$ 75.4
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.8
Regulatory Assets Currently Not Earning a Return		
Rate Case Expense - Texas	4.1	1.0
Asset Retirement Obligation - Arkansas, Louisiana	3.6	2.7
Shipe Road Transmission Project - FERC	3.3	3.1
Environmental Control Projects	—	11.0
Other Regulatory Assets Pending Final Regulatory Approval	2.4	1.9
Total Regulatory Assets Pending Final Regulatory Approval	$89.3	$ 95.9

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

AEP Texas Rate Matters (Applies to AEP)

AEP Texas Interim Transmission and Distribution Rates

As of September 30, 2017, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2017, subject to review, are estimated to be $697 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.

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 September 30, 2017, the total balance of AEP Texas' deferred storm costs is approximately $97 million including approximately $73

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million of incremental storm expenses as a regulatory asset related to Hurricane Harvey. Management is currently in the early stages of analyzing the impact of potential insurance claims and recoveries and, at this time, cannot estimate this amount. Any future insurance recoveries received will be applied to and will offset the regulatory asset and property, plant and equipment, as applicable. AEP Texas is currently evaluating recovery options for the regulatory asset; however, management believes the asset is probable of recovery. The other named hurricanes did not have a material impact on AEP's operations in the third quarter of 2017. 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.

APCo Rate Matters (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 preclude the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The amendments provide that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred from 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In 2016, the Virginia SCC issued an order that denied the petition of certain APCo industrial customers that requested the issuance of a declaratory order that would find the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, direct APCo to make biennial review filings beginning in 2016. In July 2016, the industrial customers filed an appeal of the order with the Supreme Court of Virginia. In September 2017, the Supreme Court of Virginia affirmed the Virginia SCC's 2016 order.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

Parent 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 September 30, 2017, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $709 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.

I&M Rate Matters (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. A hearing at the IURC is scheduled for January 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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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) 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, but did not propose an annual net revenue increase. Their recommended return on common equity ranged from 9.3% to 9.5%. A hearing at the MPSC is scheduled for November 2017. 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 (SCR)

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 September 30, 2017, total costs incurred related to this project, including AFUDC, were approximately $17 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. In August 2017, the district court delayed the deadline for installation of the SCR technology until March 2020.

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 includes: (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 a lower interest expense related to June 2017 debt refinancings. In October 2017, various intervenors filed testimony that included annual net revenue increase recommendations ranging from $13 million to $40 million. Intervenors recommended returns on common equity ranging from 8.6% to 8.85%. Intervenors also recommended significant delays in KPCo's proposed recoveries of: (a) depreciation expense related to Big Sandy Plant, Unit 1 (gas unit), proposing a 30-year depreciable life instead of KPCo's proposed 15-year life and (b) lease expense on Rockport Plant, Unit 2 billed from AEGCo, proposing that the approximate $100 million of lease expense for the period 2018 through 2022 be deferred with a WACC carrying charge for recovery over 10 years beginning 2023. Testimony on behalf of the Attorney General also discussed that the KPSC could consider disallowing all or a portion of the costs currently being recovered over 25 years through the Big Sandy Plant, Unit 2 retirement rider. As of September 30, 2017, KPCo's regulatory asset related to the retired Big Sandy Plant, Unit 2 was $289 million. A hearing at the KPSC is scheduled for December 2017.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters (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, the PUCO issued orders that approved OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The orders included: (a) approval of the DIR, with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed OVEC PPA and (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal. Also in 2015, OPCo subsequently filed an amended OVEC PPA application that, among other things, addressed certain PPA requirements set forth in a 2015 PUCO order. In 2016, the PUCO issued an additional order on rehearing that approved the DIR caps with additional amendments.

In 2016, the PUCO issued orders that approved a contested stipulation agreement related to the PPA rider application. Additionally, as part of these orders, the PUCO approved (a) recovery of OVEC-related net margin incurred beginning June 2016, (b) 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 (c) 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 is scheduled for November 2017.

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: (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. Although 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 SEET treatment of the Global Settlement issues described above 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 a net increase in annual revenues of $156 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 September 30, 2017, the net book value of Northeastern Plant, Unit 4 was $82 million.

In September 2017, various intervenors and the OCC staff filed testimony that included annual net revenue increase recommendations ranging from $28 million to $108 million. The recommended returns on common equity ranged from 8% to 9%. In addition, certain parties recommended investment disallowances that ranged from $27 million to $82 million related to Northeastern Plant, Unit 4 and $38 million associated with capitalized incentives. Also, a party recommended a potential refund of $43 million related to an SPP rider claiming that PSO did not adequately support

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the related SPP costs. The combined total impact could result in a write-off and refund of up to approximately $163 million. In addition, if similar plant recovery issues would apply to Northeastern Plant, Unit 3, the net book value of plant, including regulatory assets, materials and supplies inventory and CWIP of $346 million as of September 30, 2017, could be adversely impacted. A hearing at the OCC is scheduled to begin in October 2017.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. 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. The annual increase includes approximately: (a) $34 million related to additional environmental controls, including those installed at the Welsh Plant, to comply with Federal EPA mandates, (b) $25 million for additional generation, transmission and distribution investments and increased operating costs, (c) $8 million related to transmission cost recovery within SWEPCo's regional transmission organization and (d) $2 million in additional vegetation management. As part of this filing, SWEPCo requested recovery of the Texas jurisdictional share (approximately 33%) of the net book value of Welsh Plant, Unit 2 through 2042, the remaining life of Welsh Plant, Unit 3.

In April and May 2017, various intervenors and the PUCT staff filed testimony that included annual net revenue increase recommendations ranging from $36 million to $47 million. The recommended returns on common equity ranged from 9.2% to 9.35%. In addition, no parties recommended approval of SWEPCo's proposed transmission cost recovery and certain parties recommended investment disallowances that could result in write-offs of up to approximately $89 million, including approximately $40 million related to environmental investments and $25 million related to Welsh Plant, Unit 2. A hearing at the PUCT was held in June 2017.

In September 2017, the Administrative Law Judges (ALJs) issued their proposal for decision including an annual net revenue increase of $50 million including recovery of Welsh Plant, Unit 2 environmental investments as of June 30,

2016. The ALJs proposed a return on common equity of 9.6% and recovery of but no return on Welsh Plant, Unit 2. The ALJs rejected SWEPCo's proposed transmission cost recovery mechanism. The estimated potential write-off associated with the ALJs proposal is approximately $22 million which includes $9 million associated with the lack of a return on Welsh Plant, Unit 2.

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

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. The testimony also identified five individual items totaling approximately $51 million for potential disallowance relating to Louisiana's jurisdictional share of Turk Plant. As a result of SWEPCo's alleged failure to meet its continuing prudence obligations, the LPSC staff recommends one of the following potential unfavorable scenarios: (a) Even sharing of construction cost overruns between SWEPCo and ratepayers, (b) an imposition of a cost cap similar to Texas or (c) approximately a 1% reduction of the rate on common equity for the Turk Plant. As SWEPCo has included the full value of the Turk Plant in rate base since its in-service date, SWEPCo may be required to refund potential over-collections from January 2013 through the date new rates are implemented. As of September 30, 2017, if the LPSC adopts one of these potential scenarios, and disallows the five individual items, pretax write-offs could range from $50 million to $80 million and refund provisions, including interest, could range from $15 million to $27 million. Future annual revenue reductions could range from $3 million to $4 million. Management will continue to vigorously defend against these claims. If the LPSC orders in favor of one of these scenarios, it could reduce future net income and cash flows and impact financial condition. A hearing at the LPSC is scheduled for December 2017.

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. This increase is subject to LPSC staff review and is subject to refund. 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. These environmental costs are subject to prudence review. 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. 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 September 30, 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 September 30, 2017, the total net book value of Welsh Plant, Units 1 and 3 was $626 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

December 2016, the LPSC approved deferral of certain expenses related to the Louisiana jurisdictional share of environmental controls installed at Welsh Plant. In April 2017, the LPSC approved SWEPCo's recovery of these deferred costs 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 September 30, 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. Effective May

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2017, SWEPCo began recovering $131 million in investments related to its Louisiana jurisdictional share of environmental costs. SWEPCo has sought recovery of its project costs from retail customers in its current Texas base rate case at the PUCT 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.

FERC Rate Matters

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 joint 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. 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 with 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. 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. 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 joint 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. 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.

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. 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.

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5. 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. The Commitments, Guarantees and Contingencies note within AEP's and AEPTCo's 2016 Annual Reports should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP 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 September 30, 2017, no letters of credit were issued under the $3 billion revolving credit facility. In May 2017, the $500 million revolving credit facility due in June 2018 was terminated.

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 five uncommitted facilities totaling $445 million. In August 2017, AEP executed a $75 million uncommitted letter of credit facility due in August 2018. As of September 30, 2017, the Registrants' maximum future payments for letters of credit issued under the uncommitted facilities were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 123.2	October 2017 to September 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.

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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, which increased to $140 million in October 2017. 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 $76 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of September 30, 2017, SWEPCo has collected $71 million through a rider for final mine closure and reclamation costs, of which $76 million is recorded in Asset Retirement Obligations, offset by $5 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 September 30, 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 September 30, 2017, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

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 September 30, 2017, the maximum potential loss by 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	$ 42.1
APCo	8.8
I&M	3.4
OPCo	6.0
PSO	3.3
SWEPCo	3.7

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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 assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $8 million and $9 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2017.

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 September 30, 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. 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 September 30, 2017, the maximum potential amount of future payments required under the guaranteed leases was $52 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 to the extent of the sale proceeds. As of September 30, 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.

ENVIRONMENTAL CONTINGENCIES

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.

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 receiving approval of completed remediation work from the MDEQ in March 2015, I&M’s accrual was reduced. As of September 30, 2017, I&M’s accrual for all of these sites is $3 million. As the remediation work is completed, I&M’s cost may change as new information becomes available concerning either the level of contamination at the sites or changes in the scope of

remediation. Management cannot predict the amount of additional cost, if any.

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 (Applies to AEP and I&M)

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. I&M is evaluating how this reorganization affects these contracts. 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 the unlikely event Westinghouse rejects I&M's contracts, or is unable to reorganize or sell its profitable businesses in the bankruptcy, Cook Plant's operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

OPERATIONAL CONTINGENCIES

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 seeking to modify the consent decree to eliminate the obligation to install 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 October 2017, the owners filed a motion to stay their claims until January 2018, 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 settled, received summary judgment or was dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The United States Supreme Court affirmed the U.S. Court of Appeals for the Ninth Circuit's opinion. The cases were remanded to the district court for further proceedings. AEP had four pending cases, of which three were class actions and one was a single plaintiff case. In February 2017, a settlement was reached in the single plaintiff case. A settlement was also reached in the three class actions and the district court issued final approval of the settlement in June 2017.

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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. The West Virginia Supreme Court granted the appeal of the twelve non-working direct claims and heard oral argument in March 2017. 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.

6. IMPAIRMENT, DISPOSITION, AND ASSETS AND LIABILITIES HELD FOR SALE

The disclosures in this note apply to AEP only unless indicated otherwise.

IMPAIRMENT

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. 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 statement of operations.

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. 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.

DISPOSITION

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 three and nine months ended September 30, 2017 and 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 Tanner's Creek deferred costs in future rate proceedings. If any of the costs associated with Tanner's Creek are not recoverable, it could reduce future net income and impact financial condition.

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.

ASSETS AND LIABILITIES HELD FOR SALE

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In the third quarter of 2016, management determined Gavin, Waterford, Darby and Lawrenceburg Plants met the classification of held for sale. Accordingly, the four plants' assets and liabilities have been 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 $116 million for the three months ended September 30, 2016 and $42 million (excluding the $226 million pretax gain) and $312 million for the nine months ended September 30, 2017 and 2016, respectively.

	December 31, 2016
Assets:	
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 Sheets	$ 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 Sheets	$ 235.9

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7. BENEFIT PLANS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

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.

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		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$24.1	$21.4	$2.8	$2.6
Interest Cost	50.7	52.9	14.8	15.3
Expected Return on Plan Assets	(71.1)	(70.1)	(25.3)	(26.8)
Amortization of Prior Service Cost (Credit)	0.3	0.6	(17.3)	(17.3)
Amortization of Net Actuarial Loss	20.7	21.0	9.2	7.8
Net Periodic Benefit Cost (Credit)	$24.7	$25.8	$(15.8)	$(18.4)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$72.3	$64.3	$8.4	$7.7
Interest Cost	152.3	158.7	44.5	45.7
Expected Return on Plan Assets	(213.5)	(210.2)	(76.0)	(80.3)
Amortization of Prior Service Cost (Credit)	0.8	1.7	(51.8)	(51.8)
Amortization of Net Actuarial Loss	62.1	62.9	27.5	23.5
Net Periodic Benefit Cost (Credit)	$74.0	$77.4	$(47.4)	$(55.2)

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$2.3	$2.1	$0.3	$0.2
Interest Cost	6.5	6.8	2.6	2.7
Expected Return on Plan Assets	(8.9)	(8.8)	(4.1)	(4.3)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.6	2.6	1.6	1.4
Net Periodic Benefit Cost (Credit)	$2.5	$2.7	$(2.1)	$(2.5)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$7.0	$6.1	$0.8	$0.7
Interest Cost	19.3	20.4	7.9	8.1
Expected Return on Plan Assets	(26.8)	(26.5)	(12.3)	(13.0)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(7.5)	(7.5)
Amortization of Net Actuarial Loss	7.8	8.0	4.7	4.1
Net Periodic Benefit Cost (Credit)	$7.4	$8.1	$(6.4)	$(7.6)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$3.5	$3.1	$0.4	$0.4
Interest Cost	6.1	6.3	1.7	1.7
Expected Return on Plan Assets	(8.6)	(8.4)	(3.1)	(3.2)
Amortization of Prior Service Credit	—	—	(2.3)	(2.4)

Amortization of Net Actuarial Loss	2.4	2.5	1.1	0.9
Net Periodic Benefit Cost (Credit)	$3.4	$3.5	$(2.2)	$(2.6)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$10.5	$9.2	$1.2	$1.1
Interest Cost	18.2	19.0	5.2	5.2
Expected Return on Plan Assets	(25.9)	(25.2)	(9.2)	(9.6)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(7.0)	(7.1)
Amortization of Net Actuarial Loss	7.3	7.4	3.3	2.8
Net Periodic Benefit Cost (Credit)	$10.2	$10.5	$(6.5)	$(7.6)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$1.8	$1.6	$0.3	$0.2
Interest Cost	4.8	5.1	1.6	1.8
Expected Return on Plan Assets	(6.9)	(6.9)	(3.0)	(3.3)
Amortization of Prior Service Credit	—	—	(1.7)	(1.7)
Amortization of Net Actuarial Loss	2.0	2.1	1.1	0.9
Net Periodic Benefit Cost (Credit)	$1.7	$1.9	$(1.7)	$(2.1)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$5.6	$4.9	$0.7	$0.6
Interest Cost	14.5	15.4	5.0	5.3
Expected Return on Plan Assets	(20.9)	(20.8)	(9.0)	(9.7)
Amortization of Prior Service Cost (Credit)	0.1	0.1	(5.2)	(5.2)
Amortization of Net Actuarial Loss	5.9	6.1	3.3	2.8
Net Periodic Benefit Cost (Credit)	$5.2	$5.7	$(5.2)	$(6.2)

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$1.7	$1.5	$0.2	$0.2
Interest Cost	2.6	2.8	0.8	0.8
Expected Return on Plan Assets	(3.9)	(3.9)	(1.4)	(1.5)
Amortization of Prior Service Cost (Credit)	—	0.1	(1.1)	(1.1)

Amortization of Net Actuarial Loss	1.1	1.1	0.5	0.4
Net Periodic Benefit Cost (Credit)	$1.5	$1.6	$(1.0)	$(1.2)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$4.9	$4.6	$0.5	$0.5
Interest Cost	8.0	8.4	2.4	2.4
Expected Return on Plan Assets	(11.8)	(11.6)	(4.2)	(4.5)
Amortization of Prior Service Cost (Credit)	—	0.2	(3.2)	(3.2)
Amortization of Net Actuarial Loss	3.3	3.3	1.5	1.3
Net Periodic Benefit Cost (Credit)	$4.4	$4.9	$(3.0)	$(3.5)

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SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$2.1	$2.0	$0.2	$0.2
Interest Cost	3.1	3.1	0.9	0.9
Expected Return on Plan Assets	(4.2)	(4.0)	(1.5)	(1.7)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.3	1.2	0.5	0.5
Net Periodic Benefit Cost (Credit)	$2.3	$2.3	$(1.2)	$(1.4)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Service Cost	$6.5	$6.1	$0.6	$0.6
Interest Cost	9.2	9.3	2.7	2.7
Expected Return on Plan Assets	(12.6)	(12.3)	(4.7)	(5.0)
Amortization of Prior Service Cost (Credit)	—	0.2	(3.9)	(3.9)
Amortization of Net Actuarial Loss	3.7	3.6	1.7	1.5
Net Periodic Benefit Cost (Credit)	$6.8	$6.9	$(3.6)	$(4.1)

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8. 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 OPCo and AEP Texas.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.
- With the merger of TCC and TNC into AEP Utilities, Inc. to form AEP Texas, the Transmission and Distribution segment now includes certain activities related to the former AEP Utilities, Inc. that had been included in Corporate and Other.

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.

The tables below present AEP's reportable segment income statement information for the three and nine months ended September 30, 2017 and 2016 and reportable segment balance sheet information as of September 30, 2017 and December 31, 2016. These amounts include certain estimates and allocations where necessary.

	Three Months Ended September 30, 2017						
	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	$2,453.8	$ 1,149.7	$ 45.1	$441.5	$ 14.6	$ —	$ 4,104.7
Other Operating Segments	28.4	23.6	133.4	24.0	16.7	(226.1)	—
Total Revenues	$2,482.2	$ 1,173.3	$ 178.5	$465.5	$ 31.3	$ (226.1)	$ 4,104.7
Income (Loss) from Continuing Operations	$297.3	$ 144.0	$ 76.5	$33.7	$ 5.2	$ —	$ 556.7
Loss from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$297.3	$ 144.0	$ 76.5	$33.7	$ 5.2	$ —	$ 556.7

	Three Months Ended September 30, 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	$2,538.3	$ 1,245.4	$ 39.5	$823.3	$ 5.7	$ —	$ 4,652.2
Other Operating Segments	18.0	30.2	92.9	36.1	19.1	(196.3)	—
Total Revenues	$2,556.3	$ 1,275.6	$ 132.4	$859.4	$ 24.8	$ (196.3)	$ 4,652.2
Income (Loss) from Continuing Operations	$343.4	$ 155.7	$ 69.5	$(1,369.2)	$ 36.4	$ —	$ (764.2)
Loss from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$343.4	$ 155.7	$ 69.5	$(1,369.2)	$ 36.4	$ —	$ (764.2)

	Nine Months Ended September 30, 2017						
	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	$6,819.3	$ 3,242.7	$ 125.8	$1,386.8	$39.9	$ —	$11,614.5
Other Operating Segments	73.8	70.5	456.1	80.7	46.8	(727.9)	—
Total Revenues	$6,893.1	$ 3,313.2	$ 581.9	$1,467.5	$86.7	$ (727.9)	$11,614.5
Income (Loss) from Continuing Operations	$639.2	$ 374.3	$ 278.3	$246.3	$(11.0)	$ —	$1,527.1
Loss from Discontinued Operations, Net of Tax	—	—	—	—	—	—	—
Net Income (Loss)	$639.2	$ 374.3	$ 278.3	$246.3	$(11.0)	$ —	$1,527.1

	Nine Months Ended September 30, 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	$6,864.6	$ 3,398.9	$ 110.1	$2,192.5	$23.9	$ —	$12,590.0
Other Operating Segments	63.2	69.6	272.6	98.7	55.2	(559.3)	—
Total Revenues	$6,927.8	$ 3,468.5	$ 382.7	$2,291.2	$79.1	$ (559.3)	$12,590.0
Income (Loss) from Continuing Operations	$832.6	$ 387.8	$ 209.5	$(1,248.8)	$64.2	$ —	$245.3
Loss from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$832.6	$ 387.8	$ 209.5	$(1,248.8)	$61.7	$ —	$242.8

	September 30, 2017							
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)							
Total Property, Plant and Equipment	$42,722.9	$ 15,695.2	$ 6,394.2	$632.9	$359.5	$(366.5	)(b)	$ 65,438.2
Accumulated Depreciation and Amortization	13,042.9	3,766.2	156.6	161.7	180.8	(186.5	)(b)	17,121.7
Total Property Plant and Equipment - Net	$29,680.0	$ 11,929.0	$ 6,237.6	$471.2	$178.7	$(180.0	)(b)	$ 48,316.5
Total Assets	$38,136.4	$ 15,765.0	$ 7,631.2	$1,904.4	$22,339.9	$(21,812.0	)(b)(c)	$ 63,964.9
Long-term Debt Due Within One Year:								
Non-Affiliated	$1,107.2	$ 703.4	$ —	$0.1	$548.6	$—		$ 2,359.3
Long-term Debt:								
Affiliated	50.0	—	—	32.2	—	(82.2	)	—
Non-Affiliated	10,644.2	4,738.0	2,682.1	(0.3)	298.4	—		18,362.4
Total Long-term Debt	$11,801.4	$ 5,441.4	$ 2,682.1	$32.0	$847.0	$(82.2	)	$ 20,721.7

	December 31, 2016							
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)							
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	$20,354.8	$(18,888.7	)(b)(c)	$ 63,467.7
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

(a) 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.
(b) Includes eliminations due to an intercompany capital lease.
(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

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Registrant Subsidiaries' Reportable Segments (Applies to APCo, I&M, OPCo, PSO and SWEPCo)

The Registrant Subsidiaries, besides AEPTCo, 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 OPCo. Other activities are insignificant. 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 Transco 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 three and nine months ended September 30, 2017 and 2016 and reportable segment balance sheet information as of September 30, 2017 and December 31, 2016. These amounts include certain estimates and allocations where necessary.

	Three Months Ended September 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$35.9	$ —	$ —	$ 35.9
Sales to AEP Affiliates	131.3	—	0.1	131.4
Total Revenues	$167.2	$ —	$ 0.1	$ 167.3
Interest Income	$—	$ 19.5	$ (19.3) (a)	$ 0.2
Interest Expense	16.9	19.3	(19.3) (a)	16.9
Income Tax Expense	30.2	—	—	30.2
Equity Earnings in State Transcos	—	59.8	(59.8) (b)	—
Net Income	$59.8	$ 59.9	$ (59.8) (b)	$ 59.9

	Three Months Ended September 30, 2016			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$33.5	$ —	$ —	$ 33.5

Sales to AEP Affiliates	91.8	—	—		91.8
Total Revenues	$125.3	$ —	$ —		$ 125.3
Interest Income	$—	$ 14.0	$ (13.9	) (a)	$ 0.1
Interest Expense	11.0	13.9	(13.9	) (a)	11.0
Income Tax Expense	26.4	—	—		26.4
Equity Earnings in State Transcos	—	52.3	(52.3	) (b)	—
Net Income	$52.3	$ 52.4	$ (52.3	) (b)	$ 52.4

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	Nine Months Ended September 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$99.2	$ —	$ —	$ 99.2
Sales to AEP Affiliates	450.2	—	—	450.2
Total Revenues	$549.4	$ —	$ —	$ 549.4
Interest Income	$0.1	$ 58.0	$ (57.6) (a)	$ 0.5
Interest Expense	48.6	57.6	(57.6) (a)	48.6
Income Tax Expense	114.3	0.2	—	114.5
Equity Earnings in State Transcos	—	224.0	(224.0) (b)	—
Net Income	$224.0	$ 224.3	$ (224.0) (b)	$ 224.3

	Nine Months Ended September 30, 2016			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$89.6	$ —	$ —	$ 89.6
Sales to AEP Affiliates	268.4	—	—	268.4
Total Revenues	$358.0	$ —	$ —	$ 358.0
Interest Income	$—	$ 41.8	$ (41.6) (a)	$ 0.2
Interest Expense	32.3	41.6	(41.6) (a)	32.3
Income Tax Expense	73.9	—	—	73.9
Equity Earnings in State Transcos	—	153.0	(153.0) (b)	—
Net Income	$153.0	$ 153.0	$ (153.0) (b)	$ 153.0

	September 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$6,067.5	$—	$ —	$ 6,067.5
Accumulated Depreciation and Amortization	151.5	—	—	151.5
Total Transmission Property – Net	$5,916.0	$—	$ —	$ 5,916.0
Notes Receivable - Affiliated	$—	$2,500.0	$ (2,500.0) (c)	$ —
Total Assets	$6,455.2	$5,010.8	$ (4,917.1) (d)	$ 6,548.9
Total Long-term Debt	$2,475.6	$2,574.4	$ (2,500.0) (c)	$ 2,550.0

	December 31, 2016			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
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	$3,947.8	$ (3,935.5	) (d)	$ 5,349.8
Total Long-term Debt	$1,932.0	$1,950.0	$ (1,950.0	) (c)	$ 1,932.0

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Elimination of AEPTCo Parent’s equity earnings in the State Transcos.
(c) Elimination of intercompany debt.
(d) Primarily relates to the elimination of AEPTCo Parent’s investment in the State Transcos and Note Receivable from the State Transcos.

9. 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. AEP Energy Partners, LLC 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
September 30, 2017

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)					
Commodity:							
Power	MWhs	406.0	73.7	45.8	10.6	13.7	34.5
Coal	Tons	0.5	—	0.2	—	—	0.3
Natural Gas	MMBtus	48.1	2.0	1.2	—	—	18.3
Heating Oil and Gasoline	Gallons	7.9	1.5	0.7	1.8	0.8	0.9
Interest Rate	USD	$53.2	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$1,000.0	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2016

Primary Risk Exposure	Unit of Measure	AEP	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	1.4	0.7	1.6	0.8	0.9
Interest Rate	USD	$75.2	$ 0.1	$0.1	$ —	$ —	$ —
Interest Rate	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. The Registrants netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	September 30, 2017		December 31, 2016	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in millions)			
AEP	$3.5	$ 17.0	$ 7.9	$ 7.6
APCo	0.4	0.3	0.5	0.7
I&M	0.3	0.1	0.3	0.4
OPCo	0.1	—	0.2	—
PSO	—	—	0.1	—
SWEPCo	—	—	0.1	—

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The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
September 30, 2017

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		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)
	Commodity (a)	Commodity (a)	Interest Rate (a)			
	(in millions)					
Current Risk Management Assets	$277.4	$8.1	$4.2	$ 289.7	$(143.6)	$ 146.1
Long-term Risk Management Assets	348.1	3.8	—	351.9	(41.5)	310.4
Total Assets	625.5	11.9	4.2	641.6	(185.1)	456.5
Current Risk Management Liabilities	202.2	13.5	1.4	217.1	(147.7)	69.4
Long-term Risk Management Liabilities	329.6	74.0	—	403.6	(50.9)	352.7
Total Liabilities	531.8	87.5	1.4	620.7	(198.6)	422.1
Total MTM Derivative Contract Net Assets (Liabilities)	$93.7	$(75.6)	$2.8	$ 20.9	$13.5	$ 34.4

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		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)
	Commodity (a)	Commodity (a)	Interest Rate (a)			
	(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

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APCo
Fair Value of Derivative Instruments
September 30, 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	$50.4	$ (20.1)	$ 30.3
Long-term Risk Management Assets	4.9	(4.3)	0.6
Total Assets	55.3	(24.4)	30.9
Current Risk Management Liabilities	20.7	(19.8)	0.9
Long-term Risk Management Liabilities	4.8	(4.5)	0.3
Total Liabilities	25.5	(24.3)	1.2
Total MTM Derivative Contract Net Assets (Liabilities)	$29.8	$ (0.1)	$ 29.7

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	$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
September 30, 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	$27.4	$ (15.8)	$ 11.6
Long-term Risk Management Assets	3.3	(2.8)	0.5
Total Assets	30.7	(18.6)	12.1
Current Risk Management Liabilities	17.6	(15.6)	2.0
Long-term Risk Management Liabilities	3.0	(2.8)	0.2
Total Liabilities	20.6	(18.4)	2.2
Total MTM Derivative Contract Net Assets (Liabilities)	$10.1	$ (0.2)	$ 9.9

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
September 30, 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	$0.3	$ (0.1)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	0.3	(0.1)	0.2
Current Risk Management Liabilities	7.6	—	7.6
Long-term Risk Management Liabilities	130.9	—	130.9
Total Liabilities	138.5	—	138.5
Total MTM Derivative Contract Net Liabilities	$(138.2)	$ (0.1)	$ (138.3)

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
September 30, 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	$4.7	$ —	$ 4.7
Long-term Risk Management Assets	—	—	—
Total Assets	4.7	—	4.7
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$4.7	$ —	$ 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	$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

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SWEPCo
Fair Value of Derivative Instruments
September 30, 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	$12.7	$ (0.2)	$ 12.5
Long-term Risk Management Assets	0.7	—	0.7
Total Assets	13.4	(0.2)	13.2
Current Risk Management Liabilities	0.3	(0.2)	0.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.3	(0.2)	0.1
Total MTM Derivative Contract Net Assets	$13.1	$ —	$ 13.1

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
For the Three Months Ended September 30, 2017

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$0.9	$ —	$—	$—	$—	$ —
Generation & Marketing Revenues	17.7	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	0.3	0.6	—	—	(0.1)
Purchased Electricity for Resale	1.0	0.3	0.2	—	—	—
Other Operation	0.1	—	—	0.1	—	—
Maintenance	0.1	0.1	—	0.1	—	—
Regulatory Assets (a)	(8.8)	0.1	(0.8)	(8.7)	—	0.3
Regulatory Liabilities (a)	15.6	3.7	2.1	—	2.6	7.0
Total Gain (Loss) on Risk Management Contracts	$26.6	$ 4.5	$2.1	$(8.5)	$2.6	$ 7.2

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2016

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$2.4	$—	$—	$—	$—	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—
Generation & Marketing Revenues	9.2	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	1.0	1.2	0.1	—	(0.1)
Purchased Electricity for Resale	1.5	0.8	0.1	—	—	—
Other Operation	(0.4)	—	—	(0.1)	—	—
Maintenance	(0.4)	(0.1)	—	(0.1)	(0.1)	(0.1)
Regulatory Assets (a)	(22.5)	5.2	1.6	(95.4)	0.1	2.8
Regulatory Liabilities (a)	28.6	16.9	5.5	—	0.8	3.7
Total Gain (Loss) on Risk Management Contracts	$18.5	$23.8	$8.4	$(95.5)	$0.8	$ 6.3

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Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2017

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$7.0	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	38.5	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	0.6	6.3	—	—	—
Purchased Electricity for Resale	4.9	1.6	0.5	—	—	—
Other Operation	0.5	—	—	0.1	—	—
Maintenance	0.4	0.1	—	0.1	—	—
Regulatory Assets (a)	(26.8)	—	(1.0)	(25.9)	—	0.1
Regulatory Liabilities (a)	81.8	28.2	15.3	—	13.7	22.0
Total Gain (Loss) on Risk Management Contracts	$106.3	$30.5	$21.1	$(25.7)	$13.7	$ 22.1

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2016

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Vertically Integrated Utilities Revenues	$3.1	$—	$—	$—	$—	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—
Generation & Marketing Revenues	50.1	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	(0.8)	3.7	0.1	—	(0.1)
Sales to AEP Affiliates	—	2.1	5.8	—	—	—
Purchased Electricity for Resale	4.9	2.7	0.2	—	—	—
Other Operation	(1.3)	(0.1)	(0.1)	(0.3)	(0.1)	(0.2)
Maintenance	(1.6)	(0.3)	(0.1)	(0.3)	(0.2)	(0.2)
Regulatory Assets (a)	(51.0)	(7.2)	3.0	(115.9)	0.4	5.5
Regulatory Liabilities (a)	58.0	39.2	11.2	(15.2)	3.2	14.7
Total Gain (Loss) on Risk Management Contracts	$62.3	$35.6	$23.7	$(131.6)	$3.3	$ 19.7

(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."

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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. The following table shows the results of hedging gains (losses):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Gain (Loss) on Fair Value Hedging Instruments	$0.1	$(1.1)	$(0.1)	$3.0
Gain (Loss) on Fair Value Portion of Long-term Debt	(0.1)	1.1	0.1	(3.0)

During the three and nine months ended September 30, 2017 and 2016, 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 the three and nine months ended September 30, 2017 and 2016, AEP applied cash flow hedging to outstanding power derivatives. During the three and nine months ended September 30, 2017 and 2016, 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 the three and nine months ended September 30, 2017 and 2016, AEP applied cash flow hedging to outstanding interest rate derivatives. During the three and nine months ended September 30, 2017 and 2016, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related to 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 in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2017 and 2016, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

During the three and nine months ended September 30, 2017 and 2016, 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

	September 30, 2017		December 31, 2016	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
Hedging Assets (a)	$4.3	$ 4.2	$ 11.2	$ —
Hedging Liabilities (a)	79.9	—	46.7	—
AOCI Gain (Loss) Net of Tax	(49.2)	(12.2)	(23.1)	(15.7)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3.6)	(0.7)	4.3	(1.0)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

As of September 30, 2017 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 123 months.

Impact of Cash Flow Hedges on the Registrant Subsidiaries’ Balance Sheets

	September 30, 2017		December 31, 2016	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
APCo	$2.4	$ 0.7	$2.9	$ 0.7
I&M	(11.0)	(1.3)	(12.0)	(1.3)
OPCo	2.2	1.1	3.0	1.1
PSO	2.8	0.8	3.4	0.8
SWEPCo	(6.3)	(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, Standard and Poor's, and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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 September 30, 2017 and December 31, 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 tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount 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:

	September 30, 2017		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
	(in millions)		
AEP	$285.9	$ 2.5	$ 274.4
APCo	—	—	—
I&M	—	—	—

	December 31, 2016		
	Liabilities for Contracts with Cross Default Provisions Prior to	Amount of Cash	Additional Settlement Liability if Cross Default Provision

Company	Contractual Netting Arrangements	Collateral Posted	is Triggered
	(in millions)		
AEP	$259.6	$ 0.4	$ 235.8
APCo	0.1	—	—
I&M	0.1	—	—

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10. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For 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 nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the nuclear trusts, 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 and cash equivalent funds. 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.

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:

Company	September 30, 2017		December 31, 2016	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP	$20,721.7	$22,988.8	$20,391.2 (a)	$22,211.9 (a)
AEPTCo	2,550.0	2,720.8	1,932.0	1,984.3
APCo	3,979.3	4,721.3	4,033.9	4,613.2
I&M	2,658.5	2,898.7	2,471.4	2,661.6
OPCo	1,718.9	2,068.9	1,763.9	2,092.5
PSO	1,286.4	1,448.0	1,286.0	1,419.0
SWEPCo	2,441.5	2,620.7	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 6 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and 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.

The following is a summary of Other Temporary Investments:

Other Temporary Investments	September 30, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$172.9	$ —	$ —	$172.9
Fixed Income Securities – Mutual Funds (b)	103.9	—	(0.7)	103.2
Equity Securities – Mutual Funds	16.8	17.8	—	34.6
Total Other Temporary Investments	$293.6	$ 17.8	$ (0.7)	$310.7

Other Temporary Investments	December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Proceeds from Investment Sales	$ —	$ —	$ —	$ —
Purchases of Investments	12.0	0.6	13.6	1.6
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 three and nine months ended September 30, 2017 and 2016, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (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.

The following is a summary of nuclear trust fund investments:

	September 30, 2017			December 31, 2016		
	Fair	Gross Unrealized	Other-Than-Temporary	Fair	Gross Unrealized	Other-Than-Temporary

	Value	Gains	Impairments	Value	Gains	Impairments
	(in millions)					
Cash and Cash Equivalents	$20.5	$ —	$ —	$18.7	$ —	$ —
Fixed Income Securities:						
United States Government	974.3	32.6	(1.9)	785.4	27.1	(5.5)
Corporate Debt	60.0	3.5	(1.2)	60.9	2.3	(1.4)
State and Local Government	9.0	1.0	(0.2)	121.1	0.4	(0.7)
Subtotal Fixed Income Securities	1,043.3	37.1	(3.3)	967.4	29.8	(7.6)
Equity Securities - Domestic	1,369.2	783.1	(75.4)	1,270.1	677.9	(79.6)
Spent Nuclear Fuel and Decommissioning Trusts	$2,433.0	$ 820.2	$ (78.7)	$2,256.2	$ 707.7	$ (87.2)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Proceeds from Investment Sales	$519.5	$650.0	$1,808.6	$2,427.0
Purchases of Investments	525.0	656.5	1,842.2	2,452.9
Gross Realized Gains on Investment Sales	9.8	13.9	198.1	41.9
Gross Realized Losses on Investment Sales	5.2	6.5	145.4	22.2

The base cost of fixed income securities was $1 billion and $938 million as of September 30, 2017 and December 31, 2016, respectively. The base cost of equity securities was $586 million and $592 million as of September 30, 2017 and December 31, 2016, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2017 was as follows:

	Fair Value of Fixed Income Securities (in millions)
Within 1 year	$ 403.6
After 1 year through 5 years	287.9
After 5 years through 10 years	184.2
After 10 years	167.6
Total	$ 1,043.3

Fair Value Measurements of Financial Assets and Liabilities

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
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$—	$—	$—	$343.9	$343.9
Other Temporary Investments					
Restricted Cash (a)	158.6	1.4	—	12.9	172.9
Fixed Income Securities – Mutual Funds	103.2	—	—	—	103.2
Equity Securities – Mutual Funds (b)	34.6	—	—	—	34.6
Total Other Temporary Investments	296.4	1.4	—	12.9	310.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	1.2	307.9	300.3	(161.4)	448.0
Cash Flow Hedges:					
Commodity Hedges (c)	—	9.1	1.3	(6.1)	4.3
Interest Rate/Foreign Currency Hedges	—	4.2	—	—	4.2
Total Risk Management Assets	1.2	321.2	301.6	(167.5)	456.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.0	—	—	6.5	20.5
Fixed Income Securities:					
United States Government	—	974.3	—	—	974.3
Corporate Debt	—	60.0	—	—	60.0
State and Local Government	—	9.0	—	—	9.0
Subtotal Fixed Income Securities	—	1,043.3	—	—	1,043.3
Equity Securities – Domestic (b)	1,369.2	—	—	—	1,369.2
Total Spent Nuclear Fuel and Decommissioning Trusts	1,383.2	1,043.3	—	6.5	2,433.0
Total Assets	$1,680.8	$1,365.9	$301.6	$195.8	$3,544.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$3.2	$306.6	$205.9	$(174.9)	$340.8

Cash Flow Hedges:					
Commodity Hedges (c)	—	35.3	50.7	(6.1)	79.9
Fair Value Hedges	—	1.4	—	—	1.4
Total Risk Management Liabilities	$3.2	$343.3	$256.6	$(181.0)	$422.1

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 (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

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Restricted Cash for Securitized Funding (a)	$8.3	$—	$—	$0.1	$8.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	22.2	30.0	(21.3)	30.9
Total Assets	$8.3	$22.2	$30.0	$(21.2)	$39.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$21.8	$0.6	$(21.2)	$1.2

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

Assets:	Level 1	Level 2	Level 3	Other	Total
	(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
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$16.3	$12.4	$(16.6)	$12.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.0	—	—	6.5	20.5
Fixed Income Securities:					
United States Government	—	974.3	—	—	974.3
Corporate Debt	—	60.0	—	—	60.0
State and Local Government	—	9.0	—	—	9.0
Subtotal Fixed Income Securities	—	1,043.3	—	—	1,043.3
Equity Securities - Domestic (b)	1,369.2	—	—	—	1,369.2
Total Spent Nuclear Fuel and Decommissioning Trusts	1,383.2	1,043.3	—	6.5	2,433.0
Total Assets	$1,383.2	$1,059.6	$12.4	$(10.1)	$2,445.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$16.4	$2.2	$(16.4)	$2.2

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

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OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding (a)	$15.6	$—	$—	$—	$15.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.3	—	(0.1)	0.2
Total Assets	$15.6	$0.3	$—	$(0.1)	$15.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$138.5	$—	$138.5

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
September 30, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 4.8	$ (0.1)	$ 4.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.1	$ (0.1)	$ —

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

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SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2017

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Cash and Cash Equivalents (a)	$—	$—	$—	$2.2	$2.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.1	13.3	(0.2)	13.2
Total Assets	$—	$0.1	$13.3	$2.0	$15.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$0.1	$0.2	$(0.2)	$0.1

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

Assets:	Level 1	Level 2	Level 3	Other	Total
	(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 with 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 September 30, 2017 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 $(1) million in 2017 and $3 million in periods 2018-2020 and $(1) million in periods 2021-2022; Level 3 matures $23 million in 2017, $77 million in periods 2018-2020, $16 million in periods 2021-2022 and $(21) million in periods

2023-2032. 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 for the Registrant Subsidiaries.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2017 and 2016.

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The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Three Months Ended September 30, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2017	$87.3	$41.3	$15.5	$(130.5)	$9.5	$ 12.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	19.8	6.2	3.8	(0.1)	4.0	3.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	14.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(24.3)	—	—	—	—	—
Settlements	(49.2)	(16.2)	(8.4)	1.2	(6.9)	(7.6)
Transfers into Level 3 (d) (e)	5.7	—	—	—	—	—
Transfers out of Level 3 (e)	0.2	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(9.3)	(1.9)	(0.7)	(9.1)	(1.9)	4.5
Balance as of September 30, 2017	$45.0	$29.4	$10.2	$(138.5)	$4.7	$ 13.1

Three Months Ended September 30, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2016	$149.3	$(12.9)	$3.5	$(14.6)	$1.1	$ 1.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	34.2	22.7	3.8	(0.1)	0.4	4.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	12.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(34.4)	—	—	—	—	—
Settlements	(37.1)	(17.9)	(5.0)	0.9	(0.7)	(4.4)
Transfers into Level 3 (d) (e)	13.1	0.1	—	—	—	—
Transfers out of Level 3 (e)	(10.0)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(29.0)	0.9	2.2	(95.3)	0.3	0.3
Balance as of September 30, 2016	$98.4	$(7.1)	$4.5	$(109.1)	$1.1	$ 1.3

Nine Months Ended September 30, 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)	37.4	17.2	4.0	(1.0)	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)	37.2	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(29.5)	—	—	—	—	—
Settlements	(49.7)	(18.9)	(7.1)	5.1	(3.8)	(6.8)
Transfers into Level 3 (d) (e)	16.1	—	—	—	—	—
Transfers out of Level 3 (e)	(9.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	40.1	29.7	10.5	(23.6)	4.7	13.2
Balance as of September 30, 2017	$45.0	$29.4	$10.2	$(138.5)	$4.7	$ 13.1

Nine Months Ended September 30, 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)	42.1	25.5	7.0	(1.8)	(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)	45.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(16.7)	—	—	—	—	—
Settlements	(67.1)	(36.2)	(10.3)	4.0	0.4	(8.4)
Transfers into Level 3 (d) (e)	11.2	—	—	—	—	—
Transfers out of Level 3 (e)	1.1	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(64.6)	(8.2)	3.4	(127.2)	1.1	1.2
Balance as of September 30, 2016	$98.4	$(7.1)	$4.5	$(109.1)	$1.1	$ 1.3

(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 liabilities/assets or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
September 30, 2017
AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input	Low	High	Average
	(in millions)						
Energy Contracts	$233.8	$ 252.6	Discounted Cash Flow	Forward Market Price (a)	$(0.05)	$92.77	$ 35.82
				Counterparty Credit Risk (b)	10	539	204
Natural Gas Contracts	0.9	—	Discounted Cash Flow	Forward Market Price (c)	2.47	3.03	2.68
FTRs	66.9	4.0	Discounted Cash Flow	Forward Market Price (a)	(9.80)	9.37	0.32
Total	$301.6	$ 256.6					

Significant Unobservable Inputs
December 31, 2016
AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input	Low	High	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
September 30, 2017
APCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$1.0	$ 0.4	Discounted Cash Flow	Forward Market Price	$14.85	$45.72	$ 33.99
FTRs	29.0	0.2	Discounted Cash Flow	Forward Market Price	0.08	6.36	1.20
Total	$30.0	$ 0.6					

Significant Unobservable Inputs
December 31, 2016
APCo

	Fair Value		Valuation	Significant	Input/Range		
				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
September 30, 2017
I&M

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$0.6	$ 0.3	Discounted Cash Flow	Forward Market Price	$14.85	$45.72	$ 33.99
FTRs	11.8	1.9	Discounted Cash Flow	Forward Market Price	(0.02)	6.36	0.71
Total	$12.4	$ 2.2					

Significant Unobservable Inputs
December 31, 2016
I&M

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	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
September 30, 2017
OPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 138.5	Discounted Cash Flow	Forward Market Price (a)	$ 22.89	$ 61.48	$ 41.21
				Counterparty Credit Risk (b)	10	210	150
Total	$ —	$ 138.5					

Significant Unobservable Inputs
December 31, 2016
OPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable 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
September 30, 2017
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 4.8	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (9.80)	$ 1.03	$ (0.69)

Significant Unobservable Inputs
December 31, 2016
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.7	$ —	Discounted Cash Flow	Forward Market Price	$ (7.99)	$ 1.03	$ (0.36)

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Significant Unobservable Inputs
September 30, 2017
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input	Low	High	Average
	(in millions)						
Natural Gas Contracts	$0.9	$ —	Discounted Cash Flow	Forward Market Price (c)	$2.47	$3.03	$ 2.68
FTRs	12.4	0.2	Discounted Cash Flow	Forward Market Price (a)	(9.80)	1.03	(0.69)
	$13.3	$ 0.2					

Significant Unobservable Inputs
December 31, 2016
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	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 September 30, 2017 and December 31, 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)

11. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Effective Tax Rates (ETR)

The interim ETR for AEP's operating companies reflect the estimated annual ETR for 2017 and 2016, adjusted for tax expense associated with certain discrete items. The interim ETR differs from the federal statutory tax rate of 35% primarily due to tax adjustments, state income taxes and other book/tax differences which are accounted for on a flow-through basis.

The ETR from continuing operations for each of the Registrants are included in the following table. Significant variances in the ETR are described below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2017	2016	2017	2016
AEP	33.0%	40.4%	35.3%	(195.6)%
AEPTCo	33.5%	33.5%	33.8%	32.6 %
APCo	33.4%	36.1%	35.5%	36.2 %
I&M	30.6%	31.8%	30.1%	29.5 %
OPCo	36.9%	31.7%	35.6%	33.4 %
PSO	37.2%	37.7%	37.4%	36.8 %
SWEPCo	21.2%	28.9%	25.7%	26.7 %

AEP

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The decrease in the ETR is due to the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets and prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The increase in the ETR is primarily due to the increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in the ETR is also due to the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS, the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets and prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

APCo

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The decrease in the ETR is primarily due to the recording of favorable federal income tax adjustments and a decrease in pretax book income.

OPCo

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The increase in the ETR is primarily due to changes in other book/tax differences which are accounted for on a flow-through basis and the recording of federal income tax adjustments.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The increase in the ETR is primarily due to changes in other book/tax differences which are accounted for on a flow-through basis, the recording of federal income tax adjustments and an increase in pretax book income.

SWEPCo

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The decrease in the ETR is primarily due to a $10 million decrease in Income Tax Expense related to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine.

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, 2012 and 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. 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, local or foreign jurisdictions. These taxing authorities routinely examine the 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, local or non-U.S. income tax examinations by tax authorities for years before 2009.

State Tax Legislation (Applies to AEP, APCo, I&M and OPCo)

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 increased from 7.75% to 9.5%, effective July 1, 2017. The legislation is not expected to materially impact net income, cash flows or financial condition.

12. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants, unless indicated otherwise.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding:

Type of Debt	September 30, 2017	December 31, 2016	
	(in millions)		
Senior Unsecured Notes	$16,038.6	$ 14,761.0	(b)
Pollution Control Bonds	1,612.4	1,725.1	
Notes Payable	224.5	326.9	
Securitization Bonds	1,449.4	1,705.0	
Spent Nuclear Fuel Obligation (a)	267.9	266.3	
Other Long-term Debt	1,128.9	1,606.9	
Total Long-term Debt Outstanding	20,721.7	20,391.2	(b)
Long-term Debt Due Within One Year	2,359.3	3,013.4	(b)
Long-term Debt	$18,362.4	$ 17,377.8	(b)

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $311 million and $311 million as of September 30, 2017 and December 31, 2016, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

(b) 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 6 for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2017 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEPTCo	Senior Unsecured Notes	$ 125.0	3.10	2026
AEPTCo	Senior Unsecured Notes	500.0	3.75	2047
APCo	Senior Unsecured Notes	325.0	3.30	2027
I&M	Pollution Control Bonds	25.0	Variable	2019
I&M	Pollution Control Bonds	40.0	2.05	2021
I&M	Pollution Control Bonds	52.0	Variable	2021
I&M	Senior Unsecured Notes	300.0	3.75	2047
SWEPCo	Other Long-term Debt	115.0	Variable	2020
Non-Registrant:				
AEP Texas	Pollution Control Bonds	60.0	1.75	2020
AEP Texas	Senior Unsecured Notes	400.0	2.40	2022
AEP Texas	Senior Unsecured Notes	300.0	3.80	2047
KPCo	Pollution Control Bonds	65.0	2.00	2020
KPCo	Senior Unsecured Notes	65.0	3.13	2024
KPCo	Senior Unsecured Notes	40.0	3.35	2027
KPCo	Senior Unsecured Notes	165.0	3.45	2029
KPCo	Senior Unsecured Notes	55.0	4.12	2047
Transource Missouri	Other Long-term Debt	7.0	Variable	2018
Transource Energy	Other Long-term Debt	132.1	Variable	2020
Total Issuances		$ 2,771.1		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

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Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in millions)	(%)	
APCo	Senior Unsecured Notes	$ 250.0	5.00	2017
APCo	Securitization Bonds	23.5	2.008	2024
APCo	Pollution Control Bonds	104.4	Variable	2017
I&M	Notes Payable	4.9	Variable	2017
I&M	Pollution Control Bonds	25.0	Variable	2017
I&M	Notes Payable	22.3	Variable	2019
I&M	Notes Payable	23.6	Variable	2019
I&M	Notes Payable	23.9	Variable	2020
I&M	Pollution Control Bonds	52.0	Variable	2017
I&M	Notes Payable	24.3	Variable	2021
I&M	Other Long-term Debt	1.1	6.00	2025
I&M	Pollution Control Bonds	50.0	Variable	2025
OPCo	Securitization Bonds	16.2	0.958	2017
OPCo	Securitization Bonds	22.5	0.958	2018
OPCo	Securitization Bonds	7.6	2.049	2019
OPCo	Other Long-term Debt	0.1	1.149	2028
PSO	Other Long-term Debt	0.3	3.00	2027
SWEPCo	Senior Unsecured Notes	250.0	5.55	2017
SWEPCo	Other Long-term Debt	100.0	Variable	2017
SWEPCo	Other Long-term Debt	0.2	3.50	2023
SWEPCo	Other Long-term Debt	0.1	4.28	2023
SWEPCo	Notes Payable	3.3	4.58	2032
Non-Registrant:				
AEGCo	Senior Unsecured Notes	152.7	6.33	2037
AGR	Other Long-term Debt	500.0	Variable	2017
KPCo	Pollution Control Bonds	65.0	Variable	2017
KPCo	Senior Unsecured Notes	325.0	6.00	2017
TCC	Securitization Bonds	27.2	0.88	2017
TCC	Securitization Bonds	161.2	5.17	2018
TCC	Pollution Control Bonds	60.0	5.20	2030
Transource Missouri	Other Long-term Debt	130.8	Variable	2018
Total Retirements and Principal Payments		$ 2,427.2		

In October 2017, I&M retired $1 million of Notes Payable related to DCC Fuel.

In October 2017, AEP Texas retired $41 million of 5.625% Pollution Control Bonds due in 2017.

As of September 30, 2017, trustees held, on behalf of AEP, $728 million of their reacquired Pollution Control Bonds. Of this total, $104 million, $50 million and $345 million related to APCo, I&M and OPCo, respectively.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture also 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. 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 have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of September 30, 2017, no subsidiaries have exceeded their debt to capitalization limit. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the AEP subsidiary distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

As of September 30, 2017, the Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

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%. As of September 30, 2017, AEP has not exceeded its debt to capitalization limit. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

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, and a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries. 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 September 30, 2017 and December 31, 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 for the nine months ended September 30, 2017 are described in the following table:

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 September 30, 2017	Authorized Short-term Borrowing Limit	
	(in millions)						
AEPTCo	$467.2	$ 194.8	$ 235.7	$ 19.3	$ 162.9	$ 795.0	(a)
APCo	231.5	160.7	152.2	32.2	(45.9)	600.0	
I&M	367.4	12.6	205.7	12.6	(164.9)	500.0	
OPCo	280.6	56.2	141.0	27.9	(167.6)	400.0	
PSO	185.2	—	121.3	—	(118.0)	300.0	
SWEPCo	187.5	178.6	109.6	169.5	(48.3)	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 table does not include short-term lending activity of SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LP, which is a participant in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2017 and December 31, 2016 are included in Advances to Affiliates on SWEPCo's balance sheets. For the nine months ended September 30, 2017, Mutual Energy SWEPCo, LP had the following activity in the Nonutility Money Pool:

Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2017
(in millions)		
$2.0	$ 2.0	$ 2.0

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to (borrowings from) AEP as of September 30, 2017 and December 31, 2016 are included in

Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct borrowing and lending activity with AEP for the nine months ended September 30, 2017 is described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30, 2017	Loans to AEP as of September 30, 2017	Authorized Short-term Borrowing Limit	
(in millions)							
$1.1	$ 151.9	$ 1.1	$ 38.9	$ 0.9	$ 96.1	$ 75.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

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The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30,	
	2017	2016
Maximum Interest Rate	1.49%	0.91%
Minimum Interest Rate	0.92%	0.69%

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 Nine Months Ended September 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30,	
Company	2017	2016	2017	2016
AEPTCo	1.36%	0.82%	1.04%	0.74%
APCo	1.24%	0.78%	1.28%	0.79%
I&M	1.24%	0.73%	1.27%	0.78%
OPCo	1.40%	0.85%	0.98%	0.74%
PSO	1.30%	0.76%	— %	0.81%
SWEPCo	1.26%	0.79%	0.98%	0.91%

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized for Mutual Energy SWEPCo, LP in the following table:

Nine Months Ended September 30,	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 Loaned to the Nonutility Money Pool
2017	1.49 %	— %	1.27 %
2016	0.91 %	0.69 %	0.79 %

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

	Maximum Interest Rate	Minimum Interest Rate	Maximum Interest Rate	Minimum Interest Rate	Average Interest Rate	Average Interest Rate
Nine Months	for Funds	for Funds	for Funds	for Funds	for Funds	

Ended September 30,	Borrowed from AEP		Borrowed from AEP		Loaned to AEP		Loaned to AEP		Borrowed from AEP		for Funds Loaned to AEP	
2017	1.49	%	0.92	%	1.49	%	0.92	%	1.27	%	1.31	%
2016	0.91	%	0.69	%	0.91	%	0.69	%	0.80	%	0.81	%

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Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		September 30, 2017		December 31, 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)	$750.0	1.17 %	$673.0	0.70 %
AEP	Commercial Paper	295.0	1.39 %	1,040.0	1.02 %
SWEPCo	Notes Payable	14.3	2.88 %	—	— %
	Total Short-term Debt	$1,059.3		$1,713.0	

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

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	1.33 %	0.73 %	1.17 %	0.65 %
Net Uncollectible Accounts Receivable Written Off	$7.0	$7.7	$18.2	$17.5

	September 30, 2017	December 31, 2016
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$939.8	$ 945.0
Short-term – Securitized Debt of Receivables	750.0	673.0
Delinquent Securitized Accounts Receivable	44.3	42.7
Bad Debt Reserves Related to Securitization	27.8	27.7
Unbilled Receivables Related to Securitization	264.2	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)

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 was as follows:

Company	September 30, 2017	December 31, 2016
	(in millions)	
APCo	$116.9	$ 142.0
I&M	132.7	136.7
OPCo	356.3	388.3
PSO	143.4	110.4
SWEPCo	167.1	130.9

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2017	2016	2017	2016
	(in millions)			
APCo	$1.5	$1.6	$4.2	$5.4
I&M	1.8	2.0	4.9	5.6
OPCo	6.1	8.1	16.5	23.4
PSO	2.0	1.8	5.2	4.7
SWEPCo	2.0	2.1	5.4	5.3

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2017	2016	2017	2016
	(in millions)			
APCo	$335.5	$361.7	$1,029.4	$1,071.6
I&M	409.9	448.0	1,218.9	1,220.2
OPCo	616.3	750.9	1,741.7	2,011.2
PSO	407.0	390.6	1,022.6	971.9
SWEPCo	455.0	460.4	1,200.8	1,183.9

CONTROLS AND PROCEDURES

During the third quarter of 2017, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of September 30, 2017, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2017 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The AEP 2016 Annual Report on Form 10-K and the AEPTCo 2016 Annual Report included within AEPTCo’s Registration Statement includes a detailed discussion of risk factors. As of September 30, 2017, there have been no material changes to the risk factors previously disclosed in AEPTCo’s Registration Statement. As of September 30, 2017, the risk factor appearing in AEP’s 2016 Annual Report under the heading set forth below is supplemented and updated as follows:

AEP is exposed to nuclear generation risk. (Applies to AEP and I&M)

Through I&M, AEP owns the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,278 MWs, or about 7% of the generating capacity in the AEP System. AEP and I&M are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health due to an adverse incident/event resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel.
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations.
- Uncertainties with respect to contingencies and assessment amounts triggered by a loss event (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the coverage for losses of others).
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.
- Uncertainties related to reliance on a vendor for manufacturing nuclear fuel and for providing specialized engineering services and parts.

There can be no assurance that I&M’s preparations or risk mitigation measures will be adequate if these risks are triggered.

The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, although management has no reason to anticipate a serious nuclear incident at the Cook Plant, if an incident did occur, it could harm results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require AEP or I&M to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing

regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. The ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

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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. 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. In the event Westinghouse rejects I&M's contracts, or is unable to reorganize or sell its profitable businesses in the bankruptcy, Cook Plant's operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

AEP's transmission investment strategy and execution bears certain risks associated with these activities. (Applies to all Registrants)

Management expects that a growing portion of AEP's earnings in the future will be derived from transmission investments and activities. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If the FERC were to adopt a different policy, if states were to limit or restrict such policies, or if transmission needs do not continue or develop as projected, AEP's strategy of investing in transmission could be impacted. Management believes AEP's experience with transmission facilities construction and operation gives AEP an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM, SPP or other RTOs will authorize new transmission projects or will award such projects to AEP.

In October 2016, several parties filed a joint complaint with the FERC claiming that the base return on common equity used by eastern AEP affiliates 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, several parties filed a joint complaint with the FERC that states the base return on common equity used by western AEP affiliates, including 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 these complaints, including refunds from the date each complaint was filed, it could reduce future net income and cash flows and impact financial condition.

If the FERC were to lower the rate of return it has authorized for AEP's transmission investments and facilities, or if one or more states were to successfully limit FERC jurisdiction on recovery of costs on transmission investment and its return, it could reduce future net income and cash flows and negatively impact financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended September 30, 2017.

Item 5. Other Information

None

Item 6. Exhibits

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
12	Computation of Consolidated Ratio of Earnings to Fixed Charges	X	X	X	X	X	X	X
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X
95	Mine Safety Disclosures							X
101.INS	XBRL Instance Document	X	X	X	X	X	X	X
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 26, 2017

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