Large Filing Separator Sheet

Case Number: 14-1693-EL-RDR

File Date: 11/4/2015

Section: 3 of 3

Number of Pages: 166

Description of Document: Exhibits for Transcript Vol. XVII
IEU Exhibit #18 cont'd

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

Regulatory Activity

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a proceeding to address the proper treatment of APCo's authorized regulatory assets. In February and March 2015, briefs related to this proceeding were filed by various parties. As of September 30, 2015, APCo's authorized regulatory assets under review in this proceeding were $11 million. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

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

West Virginia Inquiry into Plant Closures

Subsequent to APCo's retirement of the Kanawha River Plant in May 2015, the WVPSC issued an order in July 2015 that requested APCo to maintain, for at least four years, any infrastructure installed at the Kanawha River Plant that would be used if the plant were to be converted to burn natural gas. The WVPSC stated that it would not be reasonable and prudent to completely demolish facilities that might be available in the future for conversion to natural gas before further consideration is given to the future of APCo's coal fired generation. The order indicated that the WVPSC would consider prudently incurred operating fees related to Kanawha River and Sporn Plants for recovery in a future case. In October 2015, APCo filed an application with the WVPSC to request that it be relieved of any obligation to study further the future viability of the Sporn Plant and Glen Lyn Plant units and of any obligation to maintain these units. Additionally, APCo plans to consider the Kanawha River Plant units in its preparation of an integrated resource plan to be filed with the WVPSC by December 31, 2015.

Litigation and Environmental Issues

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 179. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 256 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	2,599	2,503	9,039	9,131
Commercial	1,744	1,726	5,161	5,150
Industrial	2,493	2,600	7,520	7,665
Miscellaneous	205	205	633	636
Total Retail	7,041	7,034	22,353	22,582
Wholesale	681	563	2,335	2,507
Total KWhs	7,722	7,597	24,688	25,089

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,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	—	—	1,735	1,776
Normal - Heating (b)	3	2	1,415	1,405
Actual - Cooling (c)	804	639	1,275	1,041
Normal - Cooling (b)	809	816	1,175	1,183

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

Third Quarter of 2015 Compared to Third Quarter of 2014

Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$	49
Changes in Gross Margin:		
Retail Margins		35
Off-system Sales		(1)
Transmission Revenues		(8)
Other Revenues		2
Total Change in Gross Margin		28
Changes in Expenses and Other:		
Other Operation and Maintenance		(4)
Depreciation and Amortization		4
Allowance for Equity Funds Used During Construction		1
Interest Expense		6
Total Change in Expenses and Other		7
Income Tax Expense		(9)
Third Quarter of 2015	$	75

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

- **Retail Margins** increased $35 million primarily due to the following:
  - A $32 million increase primarily due to increases in rates in West Virginia, offset by decreases in rates in Virginia and formula rates in both jurisdictions. Of these changes, $4 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $14 million increase in weather-related usage primarily due to a 26% increase in cooling degree days.

  These increases were partially offset by:
  - A $12 million decrease in weather-normalized margin primarily due to lower industrial usage.
- **Transmission Revenues** decreased $8 million primarily due to lower Network Integrated Transmission Service (NITS) revenues. These NITS revenues are 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 $4 million primarily due to the following:
  - A $14 million increase in distribution expenses primarily related to implementation of a surcharge to recover West Virginia vegetation management expenses effective June 2015 and increased amortization of West Virginia storm costs.
  - A $3 million increase in generation operation expenses primarily related to amortizations of West Virginia Carbon Capture storage and IGCC and decommissioning expenses at disposition plants. This increase was partially offset in Gross Margin above.
  - A $2 million increase in customer accounts expenses related to customer assistance and uncollectible accounts.

  These increases were partially offset by:
  - A $7 million decrease in steam and electric plant maintenance expenses primarily at the Amos and Mountaineer Plants.
  - A $6 million decrease associated with the under recovery of transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC.
  - A $2 million decrease in PJM expenses primarily related to NITS. This decrease is partially offset by a corresponding decrease in Gross Margin above.
- **Depreciation and Amortization** expenses decreased $4 million due to prior year amortization of Virginia environmental deferrals, which ended in the first quarter of 2015.
- **Interest Expense** decreased $6 million primarily due to the following:
  - A $4 million decrease due to lower interest rates on long-term debt.
- **Income Tax Expense** increased $9 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(in millions)

Nine Months Ended September 30, 2014	$	187
Changes in Gross Margin:		
Retail Margins		116
Off-system Sales		(3)
Transmission Revenues		(6)
Other Revenues		2
Total Change in Gross Margin		109
Changes in Expenses and Other:		
Other Operation and Maintenance		—
Depreciation and Amortization		7
Taxes Other Than Income Taxes		(1)
Carrying Costs Income		2
Allowance for Equity Funds Used During Construction		6
Interest Expense		12
Total Change in Expenses and Other		26
Income Tax Expense		(47)
Nine Months Ended September 30, 2015	$	275

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

- **Retail Margins** increased $116 million primarily due to the following:
  - A $93 million increase primarily due to increases in rates in West Virginia and Virginia, as well as an adjustment due to the amended Virginia law impacting biennial reviews. Of these increases, $13 million relate to riders/ trackers which have corresponding increases in other expense items below.
  - An $18 million increase in weather-related usage primarily due to a 23% increase in cooling degree days.
  - A $10 million decrease in generation related PJM expenses due to the polar vortex in 2014 net of recovery or offsets.
  - A $7 million decrease in fuel expense from wholesale customers due to the timing of fuel recovery in 2014.
  - A $3 million decrease in consumables and allowances expense.

  These increases were partially offset by:
  - A $32 million decrease in weather-normalized margin primarily due to lower usage.
- **Transmission Revenues** decreased $6 million primarily due to lower NITS revenues.

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

- **Other Operation and Maintenance** expenses were approximately unchanged primarily due to the following:
  - A $21 million increase in PJM expenses primarily related to NITS.

  This increase was partially offset by:
  - A $21 million decrease in plant maintenance expenses primarily at Amos Plant.
- **Depreciation and Amortization** expenses decreased $7 million primarily due to the following:
  - A $9 million decrease due to prior year amortization of Virginia environmental deferrals, which ended in the first quarter of 2015.
  - A $2 million decrease due to prior year amortization of West Virginia ENEC deferrals.

  These decreases were partially offset by:
  - A $4 million increase due to a higher depreciable base.
- **Carrying Cost Income** increased $2 million related to West Virginia ENEC deferrals.
- **Allowance for Equity Funds Used During Construction** increased $6 million primarily due to increased transmission projects.
- **Interest Expense** decreased $12 million primarily due to the following:
  - A $5 million decrease due to lower interest rates on long-term debt.
  - A $3 million decrease due to higher debt component of AFUDC from increased transmission projects.
  - A $2 million decrease due to a 2014 amortization of loss on reacquired long-term debt.
- **Income Tax Expense** increased $47 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2014 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 256 for a discussion of accounting pronouncements.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUES				
Electric Generation, Transmission and Distribution	$ 685,312	$ 672,459	$ 2,184,943	$ 2,202,967
Sales to AEP Affiliates	39,389	35,455	115,740	108,439
Other Revenues	2,857	1,970	7,870	6,537
TOTAL REVENUES	727,558	709,884	2,308,553	2,317,943
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	188,576	194,303	595,308	627,943
Purchased Electricity for Resale	80,452	85,656	258,836	340,680
Purchased Electricity from AEP Affiliates	—	—	—	4,662
Other Operation	101,841	103,835	311,631	297,269
Maintenance	70,459	64,333	179,793	193,907
Depreciation and Amortization	96,295	99,889	292,735	300,125
Taxes Other Than Income Taxes	32,002	31,632	93,089	92,434
TOTAL EXPENSES	569,625	579,648	1,731,392	1,857,020
OPERATING INCOME	157,933	130,236	577,161	460,923
Other Income (Expense):				
Interest Income	290	521	1,128	1,311
Carrying Costs Income (Expense)	73	482	783	(1,130)
Allowance for Equity Funds Used During Construction	3,432	1,665	10,337	4,525
Interest Expense	(46,625)	(52,738)	(145,600)	(157,540)
INCOME BEFORE INCOME TAX EXPENSE	115,103	80,166	443,809	308,089
Income Tax Expense	40,507	31,408	168,368	121,233
NET INCOME	$ 74,596	$ 48,758	$ 275,441	$ 186,856

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net Income	$ 74,596	$ 48,758	$ 275,441	$ 186,856
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $120 and $92 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $49 and $314 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(222)	170	(91)	582
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $247 and $179 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $740 and $538 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(458)	(333)	(1,374)	(999)
TOTAL OTHER COMPREHENSIVE LOSS	(680)	(163)	(1,465)	(417)
TOTAL COMPREHENSIVE INCOME	$ 73,916	$ 48,595	$ 273,976	$ 186,439

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 260,458	$ 1,809,562	$ 1,156,461	$ 2,951	$ 3,229,432
Common Stock Dividends			(60,000)		(60,000)
Net Income			186,856		186,856
Other Comprehensive Loss				(417)	(417)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$ 260,458	$ 1,809,562	$ 1,283,317	$ 2,534	$ 3,355,871
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 260,458	$ 1,809,562	$ 1,291,876	$ 5,032	$ 3,366,928
Common Stock Dividends			(181,250)		(181,250)
Net Income			275,441		275,441
Other Comprehensive Loss				(1,465)	(1,465)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 260,458	$ 1,809,562	$ 1,386,067	$ 3,567	$ 3,459,654

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,411	$ 2,613
Restricted Cash for Securitized Funding	7,436	15,599
Advances to Affiliates	23,535	48,519
Accounts Receivable:		
Customers	118,331	114,711
Affiliated Companies	56,687	67,294
Accrued Unbilled Revenues	36,629	58,022
Miscellaneous	3,180	1,956
Allowance for Uncollectible Accounts	(3,961)	(2,364)
Total Accounts Receivable	210,866	239,619
Fuel	77,785	113,386
Materials and Supplies	126,941	131,285
Risk Management Assets – Nonaffiliated	25,970	23,792
Risk Management Assets – Affiliated	1,380	—
Deferred Income Tax Benefits	—	23,955
Regulatory Asset for Under-Recovered Fuel Costs	69,013	66,076
Prepayments and Other Current Assets	27,673	13,660
TOTAL CURRENT ASSETS	573,010	678,504
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,174,000	6,824,029
Transmission	2,271,351	2,228,029
Distribution	3,351,264	3,258,306
Other Property, Plant and Equipment	390,180	373,520
Construction Work in Progress	535,112	321,495
Total Property, Plant and Equipment	12,721,907	13,005,379
Accumulated Depreciation and Amortization	3,426,961	3,823,664
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,294,946	9,181,715
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,061,715	857,872
Securitized Assets	333,491	350,170
Long-term Risk Management Assets – Nonaffiliated	2,035	4,891
Deferred Charges and Other Noncurrent Assets	141,012	159,230
TOTAL OTHER NONCURRENT ASSETS	1,538,253	1,372,163
TOTAL ASSETS	$ 11,406,209	$ 11,232,382

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(Unaudited)

	September 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 35,224	$ —
Accounts Payable:		
General	186,317	166,821
Affiliated Companies	74,006	80,602
Long-term Debt Due Within One Year – Nonaffiliated	318,020	552,212
Long-term Debt Due Within One Year – Affiliated	—	86,000
Risk Management Liabilities – Nonaffiliated	6,902	11,017
Customer Deposits	79,237	71,766
Accrued Taxes	45,938	109,482
Accrued Interest	63,837	52,141
Other Current Liabilities	182,191	145,017
TOTAL CURRENT LIABILITIES	991,672	1,275,058
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,637,275	3,342,062
Long-term Risk Management Liabilities – Nonaffiliated	973	2,057
Deferred Income Taxes	2,410,754	2,288,842
Regulatory Liabilities and Deferred Investment Tax Credits	646,262	652,867
Asset Retirement Obligations	110,474	122,300
Employee Benefits and Pension Obligations	119,986	127,980
Deferred Credits and Other Noncurrent Liabilities	29,159	54,288
TOTAL NONCURRENT LIABILITIES	6,954,883	6,590,396
TOTAL LIABILITIES	7,946,555	7,865,454
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	260,458	260,458
Paid-in Capital	1,809,562	1,809,562
Retained Earnings	1,386,067	1,291,876
Accumulated Other Comprehensive Income (Loss)	3,567	5,032
TOTAL COMMON SHAREHOLDER'S EQUITY	3,459,654	3,366,928
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,406,209	$ 11,232,382

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 275,441	$ 186,856
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	292,735	300,125
Deferred Income Taxes	179,143	114,778
Carrying Costs Income (Expense)	(783)	1,130
Allowance for Equity Funds Used During Construction	(10,337)	(4,525)
Mark-to-Market of Risk Management Contracts	(5,902)	255
Pension Contributions to Qualified Plan Trust	(9,981)	(8,963)
Property Taxes	27,980	25,856
Fuel Over/Under-Recovery, Net	(1,729)	(114,022)
Change in Other Noncurrent Assets	(32,481)	(19,178)
Change in Other Noncurrent Liabilities	(27,399)	29,312
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	28,753	114,387
Fuel, Materials and Supplies	31,352	78,977
Accounts Payable	2,678	(65,358)
Accrued Taxes, Net	(75,290)	(43,092)
Other Current Assets	(2,628)	(3,748)
Other Current Liabilities	15,411	9,085
Net Cash Flows from Operating Activities	686,963	601,875
INVESTING ACTIVITIES		
Construction Expenditures	(456,721)	(342,291)
Change in Advances to Affiliates, Net	24,984	22,395
Other Investing Activities	18,868	(1,114)
Net Cash Flows Used for Investing Activities	(412,869)	(321,010)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	726,330	295,039
Change in Advances from Affiliates, Net	35,224	—
Retirement of Long-term Debt – Nonaffiliated	(672,552)	(512,702)
Retirement of Long-term Debt – Affiliated	(86,000)	—
Make Whole Premium on Extinguishment of Long-term Debt – Nonaffiliated	(92,658)	—
Principal Payments for Capital Lease Obligations	(3,843)	(4,255)
Dividends Paid on Common Stock	(181,250)	(60,000)
Other Financing Activities	453	1,009
Net Cash Flows Used for Financing Activities	(274,296)	(280,909)
Net Decrease in Cash and Cash Equivalents	(202)	(44)
Cash and Cash Equivalents at Beginning of Period	2,613	2,745
Cash and Cash Equivalents at End of Period	$ 2,411	$ 2,701
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 128,435	$ 136,919
Net Cash Paid for Income Taxes	33,712	22,148
Noncash Acquisitions Under Capital Leases	2,257	3,451
Construction Expenditures Included in Current Liabilities as of September 30,	80,990	54,463

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to APCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo.

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INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

Regulatory Activity

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M's seven-year TDSIC Plan for eligible transmission, distribution and storage system improvements totaling $787 million. In April 2015, I&M filed a notice with the IURC to exclude $117 million related to certain projects. In September 2015, the IURC granted I&M's motion to withdraw its application for reconsideration and/or rehearing and I&M withdrew its appeal with the Indiana Court of Appeals.

Litigation and Environmental Issues

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 179. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, 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. Plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. Management will continue to defend against the remaining claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 256 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	1,441	1,347	4,311	4,413
Commercial	1,342	1,264	3,744	3,681
Industrial	1,972	1,933	5,712	5,701
Miscellaneous	15	15	50	50
Total Retail	4,770	4,559	13,817	13,845
Wholesale	2,649	3,985	8,732	13,151
Total KWhs	7,419	8,544	22,549	26,996

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,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	—	6	2,931	3,222
Normal - Heating (b)	10	11	2,413	2,388
Actual - Cooling (c)	530	410	796	712
Normal - Cooling (b)	574	581	836	843

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

Third Quarter of 2015 Compared to Third Quarter of 2014

Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$	27
Changes in Gross Margin:		
Retail Margins		27
FERC Municipals and Cooperatives		7
Off-system Sales		(7)
Transmission Revenues		(3)
Other Revenues		6
Total Change in Gross Margin		30
Changes in Expenses and Other:		
Other Operation and Maintenance		9
Depreciation and Amortization		1
Taxes Other Than Income Taxes		1
Other Income		(3)
Interest Expense		(1)
Total Change in Expenses and Other		7
Income Tax Expense		(7)
Third Quarter of 2015	$	57

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

- **Retail Margins** increased $27 million primarily due to the following:
  - *A $15 million increase resulting from successful rate proceedings in the Indiana service territory.*
  - An $8 million increase in weather-related usage primarily due to a 29% increase in cooling degree days.
  - A $5 million increase in weather-normalized usage.

  These increases were partially offset by:
  - A $4 million decrease due to increased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.
- **Margins from FERC Municipal and Cooperatives** increased $7 million primarily due to formula rate changes.
- **Margins from Off-system Sales** decreased $7 million due to lower market prices and decreased sales volumes.
- **Other Revenues** increased $6 million primarily due to a 2014 MPSC order disallowing $4 million of lost revenue from 2012 through 2014 related to Demand Side Management.

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

- **Other Operation and Maintenance** expenses decreased $9 million primarily due to the following:
  - An $8 million decrease due to a 2014 accrual for expected environmental remediation costs.
  - A $5 million decrease in boiler plant maintenance expenses primarily due to the retirement of the Tanners Creek Plant in May 2015.

  These decreases were partially offset by:
  - A $4 million increase in nuclear expenses primarily related to Cook Plant, Unit 1 diesel generator repairs.
- **Other Income** decreased $3 million primarily due to a decrease in AFUDC Equity accrued on nuclear fuel for the reactors at Cook Plant.
- **Income Tax Expense** increased $7 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(in millions)

Nine Months Ended September 30, 2014	$	141
Changes in Gross Margin:		
Retail Margins		58
FERC Municipals and Cooperatives		32
Off-system Sales		(58)
Other Revenues		(2)
Total Change in Gross Margin		30
Changes in Expenses and Other:		
Other Operation and Maintenance		25
Taxes Other Than Income Taxes		(2)
Other Income		(2)
Interest Expense		3
Total Change in Expenses and Other		24
Income Tax Expense		(15)
Nine Months Ended September 30, 2015	$	180

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

- **Retail Margins** increased $58 million primarily due to the following:
  - A $42 million increase resulting from successful rate proceedings in the Indiana service territory.
  - A $12 million decrease in PJM related expenses primarily related to the polar vortex in 2014.

  These increases were partially offset by:
  - A $4 million decrease due to weather-normalized Residential sales.
- **Margins from FERC Municipal and Cooperatives** increased $32 million primarily due to the annual true-up adjustment of formula rates to actual costs.
- **Margins from Off-system Sales** decreased $58 million due to lower market prices and decreased sales volume.
- **Other Revenues** decreased $2 million primarily due to the following:
  - An $8 million decrease in barging deliveries to the Rockport Plant by River Transportation Division (RTD). The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging below.

  This decrease was partially offset by:
  - A $4 million increase relating to a 2014 MPSC order disallowing lost revenue from 2012 through 2014 related to Demand Side Management.
  - A $1 million increase relating to a net gain on coal procurement sales.

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

- **Other Operation and Maintenance** expenses decreased $25 million primarily due to the following:
  - A $14 million decrease in environmental costs due to a 2014 accrual of $8 million for expected environmental remediation costs and a current year $6 million reduction of an environmental liability.
  - An $8 million decrease in general and administrative expenses.
  - An $8 million decrease in distribution expenses primarily due to lower storm restoration and forestry expense.
  - A $6 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a corresponding decrease in Other Revenues from barging activities above.

  These decreases were partially offset by:
  - An $11 million increase in nuclear expenses primarily related to Cook Plant, Unit 1 diesel generator repairs.
- **Interest Expense** decreased $3 million primarily due to a lower interest rate on a remarketed pollution control bonds.
- **Income Tax Expense** increased $15 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2014 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 256 for a discussion of accounting pronouncements.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUES				
Electric Generation, Transmission and Distribution	$ 536,227	$ 520,881	$ 1,617,504	$ 1,642,721
Sales to AEP Affiliates	9,677	401	16,634	3,753
Other Revenues – Affiliated	21,672	20,832	62,183	70,821
Other Revenues – Nonaffiliated	786	749	2,626	1,298
TOTAL REVENUES	568,362	542,863	1,698,947	1,718,593
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	90,499	117,414	264,424	387,757
Purchased Electricity for Resale	41,544	20,019	147,711	52,467
Purchased Electricity from AEP Affiliates	67,281	66,561	182,239	203,807
Other Operation	141,054	144,331	407,320	431,953
Maintenance	53,727	59,043	160,907	161,854
Depreciation and Amortization	49,215	50,585	150,162	150,062
Taxes Other Than Income Taxes	21,608	22,059	66,992	64,685
TOTAL EXPENSES	464,928	480,012	1,379,755	1,452,585
OPERATING INCOME	103,434	62,851	319,192	266,008
Other Income (Expense):				
Interest Income	1,896	1,450	7,222	4,228
Allowance for Equity Funds Used During Construction	2,157	5,596	9,107	14,364
Interest Expense	(23,144)	(22,617)	(68,889)	(71,955)
INCOME BEFORE INCOME TAX EXPENSE	84,343	47,280	266,632	212,645
Income Tax Expense	27,691	20,654	86,725	71,596
NET INCOME	$ 56,652	$ 26,626	$ 179,907	$ 141,049

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	**2014**	**2015**	**2014**
Net Income	$ 56,652	$ 26,626	$ 179,907	$ 141,049
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $144 and $220 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $432 and $638 for the Nine Months Ended September 30, 2015 and 2014, Respectively	267	410	802	1,185
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $6 and $22 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $18 and $68 for the Nine Months Ended September 30, 2015 and 2014, Respectively	11	42	33	128
TOTAL OTHER COMPREHENSIVE INCOME	278	452	835	1,313
TOTAL COMPREHENSIVE INCOME	$ 56,930	$ 27,078	$ 180,742	$ 142,362

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 56,584	$ 980,896	$ 900,182	$ (15,509)	$ 1,922,153
Common Stock Dividends			(100,000)		(100,000)
Net Income			141,049		141,049
Other Comprehensive Income				1,313	1,313
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$ 56,584	$ 980,896	$ 941,231	$ (14,196)	$ 1,964,515
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 56,584	$ 980,896	$ 930,829	$ (14,360)	$ 1,953,949
Common Stock Dividends			(90,000)		(90,000)
Net Income			179,907		179,907
Other Comprehensive Income				835	835
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 56,584	$ 980,896	$ 1,020,736	$ (13,525)	$ 2,044,691

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,264	$ 1,020
Advances to Affiliates	13,508	13,481
Accounts Receivable:		
Customers	58,950	56,978
Affiliated Companies	63,135	72,582
Accrued Unbilled Revenues	2,254	503
Miscellaneous	1,409	1,625
Allowance for Uncollectible Accounts	(21)	(494)
Total Accounts Receivable	125,727	131,194
Fuel	24,687	54,623
Materials and Supplies	189,764	201,089
Risk Management Assets – Nonaffiliated	8,574	22,328
Risk Management Assets – Affiliated	2,053	—
Accrued Tax Benefits	6,232	24,788
Prepayments and Other Current Assets	27,549	27,968
TOTAL CURRENT ASSETS	399,358	476,491
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,968,224	3,741,831
Transmission	1,380,689	1,358,419
Distribution	1,758,347	1,698,409
Other Property, Plant and Equipment (September 30, 2015 and December 31, 2014 Amounts Include Coal Mining and Nuclear Fuel, December 31, 2014 Amount Includes 2015 Plant Retirement)	745,858	1,490,820
Construction Work in Progress	470,794	537,237
Total Property, Plant and Equipment	8,323,912	8,826,716
Accumulated Depreciation, Depletion and Amortization	3,084,188	3,410,341
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,239,724	5,416,375
OTHER NONCURRENT ASSETS		
Regulatory Assets	818,168	536,152
Spent Nuclear Fuel and Decommissioning Trusts	2,047,260	2,095,732
Long-term Risk Management Assets – Nonaffiliated	1,338	3,317
Deferred Charges and Other Noncurrent Assets	123,676	137,209
TOTAL OTHER NONCURRENT ASSETS	2,990,442	2,772,410
TOTAL ASSETS	$ 8,629,524	$ 8,665,276

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(dollars in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Advances from Affiliates	$ 151,004	$ 142,501
Accounts Payable:		
General	132,292	168,294
Affiliated Companies	70,812	76,010
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2015 and December 31, 2014 Amounts Include $97,953 and $85,657, Respectively, Related to DCC Fuel)	301,148	382,187
Risk Management Liabilities – Nonaffiliated	4,615	5,223
Customer Deposits	35,641	35,206
Accrued Taxes	58,791	72,742
Accrued Interest	13,263	26,677
Obligations Under Capital Leases	40,375	42,050
Other Current Liabilities	151,489	150,566
TOTAL CURRENT LIABILITIES	959,430	1,101,456
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,759,503	1,645,210
Long-term Risk Management Liabilities – Nonaffiliated	1,248	1,395
Deferred Income Taxes	1,329,163	1,264,167
Regulatory Liabilities and Deferred Investment Tax Credits	1,041,910	1,199,694
Asset Retirement Obligations	1,379,004	1,337,179
Deferred Credits and Other Noncurrent Liabilities	114,575	162,226
TOTAL NONCURRENT LIABILITIES	5,625,403	5,609,871
TOTAL LIABILITIES	6,584,833	6,711,327
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	56,584	56,584
Paid-in Capital	980,896	980,896
Retained Earnings	1,020,736	930,829
Accumulated Other Comprehensive Income (Loss)	(13,525)	(14,360)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,044,691	1,953,949
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 8,629,524	$ 8,665,276

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 179,907	$ 141,049
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	150,162	150,062
Deferred Income Taxes	38,338	15,792
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(148)	23,951
Allowance for Equity Funds Used During Construction	(9,107)	(14,364)
Mark-to-Market of Risk Management Contracts	12,926	(2,196)
Amortization of Nuclear Fuel	101,649	114,238
Fuel Over/Under-Recovery, Net	(16,055)	18,931
Change in Other Noncurrent Assets	27,286	(36,596)
Change in Other Noncurrent Liabilities	(6,330)	66,502
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5,467	59,646
Fuel, Materials and Supplies	29,609	14,884
Accounts Payable	(14,001)	(12,052)
Accrued Taxes, Net	4,605	30,719
Other Current Assets	6,923	11,741
Other Current Liabilities	(9,276)	(8,201)
Net Cash Flows from Operating Activities	501,955	574,106
INVESTING ACTIVITIES		
Construction Expenditures	(337,021)	(345,369)
Change in Advances to Affiliates, Net	(27)	42,364
Purchases of Investment Securities	(1,479,149)	(789,461)
Sales of Investment Securities	1,437,336	746,272
Acquisitions of Nuclear Fuel	(53,262)	(109,224)
Other Investing Activities	9,000	11,773
Net Cash Flows Used for Investing Activities	(423,123)	(443,645)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	210,687	99,323
Change in Advances from Affiliates, Net	8,503	95,899
Retirement of Long-term Debt – Nonaffiliated	(178,471)	(190,550)
Principal Payments for Capital Lease Obligations	(29,875)	(35,660)
Dividends Paid on Common Stock	(90,000)	(100,000)
Other Financing Activities	568	628
Net Cash Flows Used for Financing Activities	(78,588)	(130,360)
Net Increase in Cash and Cash Equivalents	244	101
Cash and Cash Equivalents at Beginning of Period	1,020	1,317
Cash and Cash Equivalents at End of Period	$ 1,264	$ 1,418
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 77,450	$ 75,789
Net Cash Paid (Received) for Income Taxes	17,203	(1,475)
Noncash Acquisitions Under Capital Leases	1,990	5,015
Construction Expenditures Included in Current Liabilities as of September 30,	51,582	69,241
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	31,140	11
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2,136	3,208

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to I&M's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M.

OHIO POWER COMPANY AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

Regulatory Activity

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. In June 2015, the Supreme Court of Ohio issued a decision that reversed, as requested by OPCo, the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. In September 2015, the Supreme Court of Ohio denied the IEU's request for reconsideration and in October 2015 this matter was remanded back to the PUCO for reinstatement of the WACC rate.

June 2012 - May 2015 Ohio ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio, which has scheduled oral arguments for the fourth quarter of 2015.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. In April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. In May 2015, the PUCO granted intervenors requests for rehearing. As of September 30, 2015, OPCo's net deferred capacity costs balance was $392 million, including debt carrying costs. Through September 30, 2015, OPCo has collected $183 million in deferred capacity costs, and related carrying charges.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

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

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.

June 2015 - May 2018 ESP Including PPA Application

In December 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 effective June 2015 through May 2018. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the Distribution Investment Rider (DIR) with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order. In July 2015, intervenors filed appeals with the Supreme Court of Ohio that included opposition to the authorization of a PPA rider and the modifications to a transmission rider.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider. In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) included the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units. A hearing at the PUCO related to the PPA commenced in September 2015. In October 2015, the PUCO staff submitted testimony that opposed the PPA application as currently proposed but concluded that, with changes, a PPA could be in the public interest.

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

Litigation and Environmental Issues

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 179. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 256 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in millions of KWhs)			
Retail:				
Residential	3,788	3,513	11,249	11,189
Commercial	3,929	3,714	11,074	10,838
Industrial	3,711	3,647	11,081	10,822
Miscellaneous	28	26	88	88
Total Retail (a)	11,456	10,900	33,492	32,937
Wholesale (b)	497	575	1,460	1,727
Total KWhs	11,953	11,475	34,952	34,664

(a) Represents energy delivered to distribution customers.
(b) 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, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in degree days)			
Actual - Heating (a)	—	1	2,575	2,540
Normal - Heating (b)	6	7	2,073	2,074
Actual - Cooling (c)	620	581	970	943
Normal - Cooling (b)	666	663	956	946

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

Third Quarter of 2015 Compared to Third Quarter of 2014

Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$	54
Changes in Gross Margin:		
Retail Margins		106
Off-system Sales		(10)
Transmission Revenues		(37)
Other Revenues		1
Total Change in Gross Margin		60
Changes in Expenses and Other:		
Other Operation and Maintenance		(11)
Depreciation and Amortization		(9)
Taxes Other Than Income Taxes		(4)
Carrying Costs Income		(7)
Interest Expense		(1)
Total Change in Expenses and Other		(32)
Income Tax Expense		(10)
Third Quarter of 2015	$	72

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

- **Retail Margins** increased $106 million primarily due to the following:
  - A $65 million increase in transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
  - A $33 million regulatory provision recorded in 2014.
  - A $7 million increase in revenues associated with the Distribution Investment Rider.
  - A $7 million increase in revenues associated with the *gridSMART®*, Enhanced Service Reliability and Retail Stability Riders. These riders have corresponding increases in other expense items below.

  These increases were partially offset by:
  - A $14 million decrease in base rates due to the discontinuance of seasonal rates.
  - A $14 million decrease in revenues associated with the recovery of 2012 storm costs under the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- **Margins from Off-system Sales** decreased $10 million primarily due to losses from a legacy power contract.
- **Transmission Revenues** decreased $37 million primarily due to a decrease in Network Integrated Transmission Service (NITS) revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

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

- **Other Operation and Maintenance** expenses increased $11 million primarily due to the following:
  - A $19 million increase in recoverable PJM expenses.
  - A $4 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $14 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
- **Depreciation and Amortization** expenses increased $9 million primarily due to the following:
  - A $4 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
  - A $3 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - A $3 million increase in *gridSMART®* capital carrying charges primarily due to a rider rate increase effective June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $4 million primarily due to an increase in property taxes due to additional investment in transmission and distribution assets and higher tax rates.
- **Carrying Costs Income** decreased $7 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- **Income Tax Expense** increased $10 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(In Millions)

Nine Months Ended September 30, 2014	$	171
Changes in Gross Margin:		
Retail Margins		133
Off-system Sales		(12)
Transmission Revenues		(72)
Other Revenues		8
Total Change in Gross Margin		57
Changes in Expenses and Other:		
Other Operation and Maintenance		(3)
Depreciation and Amortization		(13)
Taxes Other Than Income Taxes		(14)
Other Income		(2)
Carrying Costs Income		(10)
Interest Expense		1
Total Change in Expenses and Other		(41)
Income Tax Expense		(2)
Nine Months Ended September 30, 2015	$	185

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

- **Retail Margins** increased $133 million primarily due to the following:
  - A $91 million increase in transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
  - A $33 million regulatory provision recorded in 2014.
  - A $22 million increase in revenues associated with the Distribution Investment Rider.
  - A $14 million increase in revenues associated with the *gridSMART*®, Enhanced Service Reliability and Retail Stability Riders. These riders have corresponding increases in other expense items below.

  These increases were partially offset by:
  - A $19 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues and associated deferrals. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - An $11 million decrease in revenues associated with the recovery of 2012 storm costs under the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
  - A $6 million decrease in revenues associated with the Universal Service Fund (USF) surcharge. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - A $4 million decrease in base rates due to the discontinuance of seasonal rates.
- **Margins from Off-system Sales** decreased $12 million primarily due to losses from a legacy power contract.
- **Transmission Revenues** decreased $72 million primarily due to the following:
  - A $44 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.
  - A $12 million decrease in revenues related to a lower annual transmission formula rate true-up.
  - A $9 million transmission regulatory settlement in 2015.
- **Other Revenues** increased $8 million primarily due to increased pole attachment revenue.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $3 million primarily due to the following:
  - A $33 million increase in recoverable PJM expenses.
  - A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

  These increases were partially offset by:
  - A $19 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $12 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $6 million decrease 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.
- **Depreciation and Amortization** expenses increased $13 million primarily due to the following:
  - A $9 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - A $5 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $14 million primarily due to an increase in property taxes due to additional investment in transmission and distribution assets and higher tax rates.
- **Carrying Costs Income** decreased $10 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2014 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 256 for a discussion of accounting pronouncements.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUES				
Electricity, Transmission and Distribution	$ 775,905	$ 793,900	$ 2,320,372	$ 2,380,768
Sales to AEP Affiliates	4,426	43,733	79,690	120,154
Other Revenues	1,953	1,564	6,416	4,628
TOTAL REVENUES	782,284	839,197	2,406,478	2,505,550
EXPENSES				
Purchased Electricity for Resale	173,094	48,541	431,608	191,730
Purchased Electricity from AEP Affiliates	45,834	315,903	462,645	897,658
Amortization of Generation Deferrals	55,466	26,655	122,221	82,818
Other Operation	170,144	145,163	446,817	428,074
Maintenance	39,437	53,724	121,224	136,965
Depreciation and Amortization	63,757	54,968	178,609	165,152
Taxes Other Than Income Taxes	93,666	89,564	283,092	268,734
TOTAL EXPENSES	641,398	734,518	2,046,216	2,171,131
OPERATING INCOME	140,886	104,679	360,262	334,419
Other Income (Expense):				
Interest Income	1,165	1,986	4,328	8,159
Carrying Costs Income (Expense)	(1,576)	5,606	10,037	19,594
Allowance for Equity Funds Used During Construction	2,228	1,825	7,015	4,893
Interest Expense	(32,593)	(31,171)	(96,313)	(96,937)
INCOME BEFORE INCOME TAX EXPENSE	110,110	82,925	285,329	270,128
Income Tax Expense	38,541	28,865	100,641	98,759
NET INCOME	$ 71,569	$ 54,060	$ 184,688	$ 171,369

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net Income	$ 71,569	$ 54,060	$ 184,688	$ 171,369
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $185 and $185 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $555 and $611 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(344)	(343)	(1,030)	(1,134)
TOTAL COMPREHENSIVE INCOME	$ 71,225	$ 53,717	$ 183,658	$ 170,235

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 321,201	$ 663,782	$ 633,203	$ 7,079	$ 1,625,265
Common Stock Dividends			(35,000)		(35,000)
Net Income			171,369		171,369
Other Comprehensive Loss				(1,134)	(1,134)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$ 321,201	$ 663,782	$ 769,572	$ 5,945	$ 1,760,500
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 321,201	$ 838,782	$ 814,625	$ 5,602	$ 1,980,210
Common Stock Dividends			(156,250)		(156,250)
Net Income			184,688		184,688
Other Comprehensive Loss				(1,030)	(1,030)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 321,201	$ 838,782	$ 843,063	$ 4,572	$ 2,007,618

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3,248	$ 2,870
Restricted Cash for Securitized Funding	16,195	28,687
Advances to Affiliates	279,129	312,473
Accounts Receivable:		
Customers	35,711	57,906
Affiliated Companies	57,240	79,822
Accrued Unbilled Revenues	39,236	35,755
Miscellaneous	1,246	927
Allowance for Uncollectible Accounts	(421)	(171)
Total Accounts Receivable	133,012	174,239
Notes Receivable Due Within One Year – Affiliated	—	86,000
Materials and Supplies	75,878	60,909
Risk Management Assets	—	7,242
Deferred Income Tax Benefits	20,568	49,306
Accrued Tax Benefits	5,030	6,100
Prepayments and Other Current Assets	11,141	8,997
TOTAL CURRENT ASSETS	544,201	736,823
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,181,389	2,104,613
Distribution	4,231,051	4,087,601
Other Property, Plant and Equipment	446,485	390,848
Construction Work in Progress	212,093	218,667
Total Property, Plant and Equipment	7,071,018	6,801,729
Accumulated Depreciation and Amortization	2,086,931	2,038,120
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,984,087	4,763,609
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32,245	32,245
Regulatory Assets	1,150,864	1,318,939
Securitized Assets	91,899	109,999
Long-term Risk Management Assets	23,265	45,102
Deferred Charges and Other Noncurrent Assets	118,942	264,150
TOTAL OTHER NONCURRENT ASSETS	1,417,215	1,770,435
TOTAL ASSETS	$ 6,945,503	$ 7,270,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(dollars in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 141,073	$ 145,328
Affiliated Companies	88,324	172,741
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2015 and December 31, 2014 Amounts Include $45,864 and $45,427, Respectively, Related to Ohio Phase-in-Recovery Funding)	395,938	131,497
Risk Management Liabilities	2,823	1,943
Customer Deposits	60,235	53,922
Accrued Taxes	285,003	420,772
Accrued Interest	45,452	34,279
Other Current Liabilities	147,567	179,093
TOTAL CURRENT LIABILITIES	1,166,415	1,139,575
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2015 and December 31, 2014 Amounts Include $141,177 and $187,041, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,770,112	2,165,626
Long-term Risk Management Liabilities	4,871	3,013
Deferred Income Taxes	1,402,369	1,405,620
Regulatory Liabilities and Deferred Investment Tax Credits	535,458	514,691
Employee Benefits and Pension Obligations	29,978	36,662
Deferred Credits and Other Noncurrent Liabilities	28,682	25,470
TOTAL NONCURRENT LIABILITIES	3,771,470	4,151,082
TOTAL LIABILITIES	4,937,885	5,290,657
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	321,201	321,201
Paid-in Capital	838,782	838,782
Retained Earnings	843,063	814,625
Accumulated Other Comprehensive Income (Loss)	4,572	5,602
TOTAL COMMON SHAREHOLDER'S EQUITY	2,007,618	1,980,210
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 6,945,503	$ 7,270,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 184,688	$ 171,369
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	178,609	165,152
Amortization of Generation Deferrals	122,221	82,818
Deferred Income Taxes	28,099	27,990
Carrying Costs Income	(10,037)	(19,594)
Allowance for Equity Funds Used During Construction	(7,015)	(4,893)
Mark-to-Market of Risk Management Contracts	31,818	(5,003)
Pension Contributions to Qualified Plan Trust	(7,671)	(6,547)
Property Taxes	148,407	148,124
Fuel Over/Under-Recovery, Net	(15,674)	37,326
Deferral of Ohio Capacity Costs, Net	(30,662)	(138,737)
Change in Other Noncurrent Assets	29,168	35,962
Change in Other Noncurrent Liabilities	30,913	59,081
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	41,227	(20,395)
Materials and Supplies	(14,969)	(1,247)
Accounts Payable	(78,831)	(83,029)
Customer Deposits	6,313	2,973
Accrued Taxes, Net	(134,699)	(173,470)
Other Current Assets	(3,233)	(947)
Other Current Liabilities	(4,707)	26,039
Net Cash Flows from Operating Activities	493,965	302,972
INVESTING ACTIVITIES		
Construction Expenditures	(346,831)	(327,972)
Change in Restricted Cash for Securitized Funding	12,492	1,653
Change in Advances to Affiliates, Net	33,344	315,325
Proceeds from Notes Receivable – Affiliated	86,000	178,580
Other Investing Activities	10,882	6,807
Net Cash Flows from (Used for) Investing Activities	(204,113)	174,393
FINANCING ACTIVITIES		
Retirement of Long-term Debt – Nonaffiliated	(131,484)	(438,583)
Principal Payments for Capital Lease Obligations	(2,937)	(3,912)
Dividends Paid on Common Stock	(156,250)	(35,000)
Other Financing Activities	1,197	1,015
Net Cash Flows Used for Financing Activities	(289,474)	(476,480)
Net Increase in Cash and Cash Equivalents	378	885
Cash and Cash Equivalents at Beginning of Period	2,870	3,004
Cash and Cash Equivalents at End of Period	$ 3,248	$ 3,889
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 79,019	$ 90,188
Net Cash Paid for Income Taxes	24,060	15,523
Noncash Acquisitions Under Capital Leases	2,115	4,505
Construction Expenditures Included in Current Liabilities as of September 30,	30,209	45,691

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to OPCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

EXECUTIVE OVERVIEW

Regulatory Activity

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 of Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% to be effective in January 2016, except for the $44 million for environmental investments, which is effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO's investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, certain intervenors did not support an increase in depreciation expense for the Northeastern Plant, Units 3 and 4 to permit cost recovery by Unit 3's 2026 retirement date as the proposals called for no change in existing cost recovery by 2040. Hearings at the OCC are scheduled for December 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the "2015 Oklahoma Base Rate Case" section of PSO Rate Matters in Note 4.

Litigation and Environmental Issues

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 179. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 256 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in millions of KWhs)			
Retail:				
Residential	2,126	1,981	4,966	4,978
Commercial	1,568	1,455	4,028	3,905
Industrial	1,408	1,407	4,039	3,939
Miscellaneous	365	356	958	956
Total Retail	5,467	5,199	13,991	13,778
Wholesale	28	42	166	318
Total KWhs	5,495	5,241	14,157	14,096

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, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in degree days)			
Actual - Heating (a)	—	—	1,176	1,417
Normal - Heating (b)	1	1	1,089	1,086
Actual - Cooling (c)	1,444	1,259	2,103	1,935
Normal - Cooling (b)	1,387	1,394	2,053	2,058

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

Third Quarter of 2015 Compared to Third Quarter of 2014

Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$	45
Changes in Gross Margin:		
Retail Margins (a)		13
Transmission Revenues		1
Other Revenues		1
Total Change in Gross Margin		15
Changes in Expenses and Other:		
Other Operation and Maintenance		(11)
Depreciation and Amortization		(6)
Allowance for Equity Funds Used During Construction		2
Interest Expense		(1)
Total Change in Expenses and Other		(16)
Income Tax Expense		1
Third Quarter of 2015	$	45

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

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

- **Retail Margins** increased $13 million primarily due to the following:
  - An $11 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.
  - A $9 million increase in weather-related usage primarily due to a 15% increase in cooling degree days.

  These increases were partially offset by:
  - An $8 million decrease primarily due to lower weather-normalized residential sales.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $11 million primarily due to the following:
  - A $5 million increase in distribution expenses primarily due to increased vegetation management expenses and amortization of 2013 storm restoration expenses beginning in the second quarter of 2015.
  - A $2 million increase in generation plant maintenance expenses.
  - A $2 million increase in transmission expenses primarily due to increased SPP transmission services.
- **Depreciation and Amortization** expenses increased $6 million primarily due to the following:
  - A $4 million increase in amortization related to an advanced metering rider implemented in November 2014.
  - A $2 million increase due to a higher depreciable base.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(in millions)

Nine Months Ended September 30, 2014	$	76
Changes in Gross Margin:		
Retail Margins (a)		32
Transmission Revenues		2
Other Revenues		1
Total Change in Gross Margin		35
Changes in Expenses and Other:		
Other Operation and Maintenance		(5)
Depreciation and Amortization		(17)
Allowance for Equity Funds Used During Construction		4
Interest Expense		(3)
Total Change in Expenses and Other		(21)
Income Tax Expense		(4)
Nine Months Ended September 30, 2015	$	86

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

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

- **Retail Margins** increased $32 million primarily due to the following:
  - A $27 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.
  - A $7 million net increase in weather-related usage primarily due to a 9% increase in cooling degree days, partially offset by a decrease in heating degree days.

  These increases were partially offset by:
  - A $3 million decrease primarily due to lower weather-normalized residential sales.

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

- **Other Operation and Maintenance** expenses increased $5 million primarily due to the following:
  - A $3 million increase in distribution expenses primarily due to amortization of 2013 storm restoration expenses beginning in the second quarter of 2015.
  - A $3 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $2 million increase in energy efficiency program expenses.

  These increases were partially offset by:
  - A $3 million decrease in generation plant maintenance expenses.
- **Depreciation and Amortization** expenses increased $17 million primarily due to the following:
  - A $10 million increase in amortization related to an advanced metering rider implemented in November 2014.
  - A $6 million increase due to a higher depreciable base.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to increased environmental projects.
- **Interest Expense** increased $3 million primarily due to increased long-term debt outstanding.
- **Income Tax Expense** increased $4 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2014 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 256 for a discussion of accounting pronouncements.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$ 418,592	$ 415,193	$ 1,040,876	$ 1,028,427
Sales to AEP Affiliates	1,062	789	3,505	6,240
Other Revenues	709	1,009	2,258	2,524
TOTAL REVENUES	420,363	416,991	1,046,639	1,037,191
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	87,680	85,018	226,260	192,567
Purchased Electricity for Resale	103,226	117,521	253,785	301,816
Purchased Electricity from AEP Affiliates	—	—	—	11,024
Other Operation	77,541	71,605	199,334	193,101
Maintenance	27,239	21,800	74,322	76,223
Depreciation and Amortization	30,832	24,496	90,148	73,085
Taxes Other Than Income Taxes	9,327	9,137	27,843	27,757
TOTAL EXPENSES	335,845	329,577	871,692	875,573
OPERATING INCOME	84,518	87,414	174,947	161,618
Other Income (Expense):				
Interest Income	127	137	255	138
Allowance for Equity Funds Used During Construction	2,342	194	5,952	2,215
Interest Expense	(14,950)	(13,913)	(44,372)	(41,009)
INCOME BEFORE INCOME TAX EXPENSE	72,037	73,832	136,782	122,962
Income Tax Expense	27,298	28,746	51,260	46,979
NET INCOME	$ 44,739	$ 45,086	$ 85,522	$ 75,983

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	**2014**	**2015**	**2014**
Net Income	$ 44,739	$ 45,086	$ 85,522	$ 75,983
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $101 and $102 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $306 and $337 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(189)	(190)	(569)	(626)
TOTAL COMPREHENSIVE INCOME	$ 44,550	$ 44,896	$ 84,953	$ 75,357

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 157,230	$ 364,037	$ 415,076	$ 5,758	$ 942,101
Net Income			75,983		75,983
Other Comprehensive Loss				(626)	(626)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$ 157,230	$ 364,037	$ 491,059	$ 5,132	$ 1,017,458
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 157,230	$ 364,037	$ 502,005	$ 4,943	$ 1,028,215
Net Income			85,522		85,522
Other Comprehensive Loss				(569)	(569)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 157,230	$ 364,037	$ 587,527	$ 4,374	$ 1,113,168

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,663	$ 1,352
Advances to Affiliates	116,345	—
Accounts Receivable:		
Customers	24,770	28,448
Affiliated Companies	25,117	22,114
Miscellaneous	9,559	6,026
Allowance for Uncollectible Accounts	(359)	(147)
Total Accounts Receivable	59,087	56,441
Fuel	15,864	16,436
Materials and Supplies	52,519	50,880
Risk Management Assets	1,035	—
Deferred Income Tax Benefits	8,975	—
Accrued Tax Benefits	19,093	24,369
Regulatory Asset for Under-Recovered Fuel Costs	—	35,699
Prepayments and Other Current Assets	7,280	6,524
TOTAL CURRENT ASSETS	281,861	191,701
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,296,921	1,264,724
Transmission	805,505	788,911
Distribution	2,185,778	2,080,221
Other Property, Plant and Equipment (Including Plant to be Retired)	435,807	421,568
Construction Work in Progress	274,470	204,753
Total Property, Plant and Equipment	4,998,481	4,760,177
Accumulated Depreciation and Amortization	1,383,116	1,319,554
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,615,365	3,440,623
OTHER NONCURRENT ASSETS		
Regulatory Assets	180,605	154,327
Employee Benefits and Pension Assets	21,231	19,335
Deferred Charges and Other Noncurrent Assets	15,664	7,557
TOTAL OTHER NONCURRENT ASSETS	217,500	181,219
TOTAL ASSETS	$ 4,114,726	$ 3,813,543

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(Unaudited)

	September 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 154,249
Accounts Payable:		
General	98,777	92,672
Affiliated Companies	37,267	51,744
Long-term Debt Due Within One Year – Nonaffiliated	150,437	427
Risk Management Liabilities	70	918
Customer Deposits	50,147	48,700
Accrued Taxes	36,637	20,887
Accrued Interest	15,499	12,699
Regulatory Liability for Over-Recovered Fuel Costs	41,175	—
Other Current Liabilities	56,255	58,878
TOTAL CURRENT LIABILITIES	486,264	441,174
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,140,536	1,040,609
Long-term Risk Management Liabilities	8	—
Deferred Income Taxes	958,168	898,352
Regulatory Liabilities and Deferred Investment Tax Credits	339,161	334,479
Asset Retirement Obligations	42,680	37,030
Employee Benefits and Pension Obligations	16,456	20,095
Deferred Credits and Other Noncurrent Liabilities	18,285	13,589
TOTAL NONCURRENT LIABILITIES	2,515,294	2,344,154
TOTAL LIABILITIES	3,001,558	2,785,328
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	157,230	157,230
Paid-in Capital	364,037	364,037
Retained Earnings	587,527	502,005
Accumulated Other Comprehensive Income (Loss)	4,374	4,943
TOTAL COMMON SHAREHOLDER'S EQUITY	1,113,168	1,028,215
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,114,726	$ 3,813,543

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 85,522	$ 75,983
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	90,148	73,085
Deferred Income Taxes	40,052	27,327
Allowance for Equity Funds Used During Construction	(5,952)	(2,215)
Mark-to-Market of Risk Management Contracts	(1,875)	432
Pension Contributions to Qualified Plan Trust	(5,795)	(4,439)
Property Taxes	(8,049)	(7,970)
Fuel Over/Under-Recovery, Net	76,874	(33,246)
Change in Other Noncurrent Assets	(13,066)	2,035
Change in Other Noncurrent Liabilities	7,733	(2,015)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(2,646)	333
Fuel, Materials and Supplies	(1,067)	5,755
Accounts Payable	(9,339)	(28,643)
Accrued Taxes, Net	21,026	32,131
Other Current Assets	(1,866)	(4,034)
Other Current Liabilities	7,977	17,024
Net Cash Flows from Operating Activities	279,677	151,543
INVESTING ACTIVITIES		
Construction Expenditures	(262,887)	(256,741)
Change in Advances to Affiliates, Net	(116,345)	—
Other Investing Activities	7,679	2,881
Net Cash Flows Used for Investing Activities	(371,553)	(253,860)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	248,785	74,973
Change in Advances from Affiliates, Net	(154,249)	64,095
Retirement of Long-term Debt – Nonaffiliated	(319)	(34,010)
Principal Payments for Capital Lease Obligations	(2,765)	(2,785)
Other Financing Activities	735	595
Net Cash Flows from Financing Activities	92,187	102,868
Net Increase in Cash and Cash Equivalents	311	551
Cash and Cash Equivalents at Beginning of Period	1,352	1,277
Cash and Cash Equivalents at End of Period	$ 1,663	$ 1,828
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 40,562	$ 37,458
Net Cash Paid (Received) for Income Taxes	12,772	(416)
Noncash Acquisitions Under Capital Leases	1,546	2,098
Construction Expenditures Included in Current Liabilities as of September 30,	37,328	33,527

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

EXECUTIVE OVERVIEW

Regulatory Activity

2012 Texas Base Rate Case

Upon rehearing in January 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 May 2014, intervenors filed appeals of the order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses. If certain parts of the PUCT order are overturned it could reduce future net income and cash flows and impact financial condition. See the "2012 Texas Base Rate Case" section of SWEPCo Rate Matters in Note 4.

2012 Louisiana Formula Rate Filing

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

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchased power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015. These increases are subject to LPSC staff review and are subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2024 for Welsh Plant, Units 1 and 3 will cost approximately $700 million, excluding AFUDC. As of September 30, 2015, SWEPCo has incurred costs of $303 million, including AFUDC, and has remaining contractual construction obligations of $62 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" and "Climate Change, CO_2 Regulation and Energy Policy" sections of "Environmental Issues" within "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries". As of September 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $529 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

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

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

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

Litigation and Environmental Issues

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 179. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 256 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in millions of KWhs)			
Retail:				
Residential	2,087	1,949	5,135	4,974
Commercial	1,782	1,744	4,705	4,583
Industrial	1,419	1,511	4,079	4,453
Miscellaneous	19	20	60	60
Total Retail	5,307	5,224	13,979	14,070
Wholesale	2,460	2,458	7,092	7,022
Total KWhs	7,767	7,682	21,071	21,092

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, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in degree days)			
Actual - Heating (a)	—	—	920	1,039
Normal - Heating (b)	1	1	733	748
Actual - Cooling (c)	1,500	1,232	2,278	1,917
Normal - Cooling (b)	1,408	1,404	2,175	2,162

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

Third Quarter of 2015 Compared to Third Quarter of 2014

Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2014	$	73
Changes in Gross Margin:		
Retail Margins (a)		28
Off-system Sales		(3)
Transmission Revenues		4
Other Revenues		(1)
Total Change in Gross Margin		28
Changes in Expenses and Other:		
Other Operation and Maintenance		(17)
Depreciation and Amortization		(2)
Taxes Other Than Income Taxes		(1)
Allowance for Equity Funds Used During Construction		4
Interest Expense		2
Total Change in Expenses and Other		(14)
Income Tax Expense		(6)
Third Quarter of 2015	$	81

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

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

- **Retail Margins** increased $28 million primarily due to the following:
  - A $25 million increase primarily due to revenue increases from rate riders in Louisiana and Texas.
  - A $16 million increase in weather-related usage primarily due to an 18% increase in cooling degree days.

  These increases were partially offset by:
  - An $11 million decrease primarily due to lower weather-normalized retail sales.
- **Margins from Off-system Sales** decreased $3 million primarily due to lower market prices and decreased sales volumes.
- **Transmission Revenues** increased $4 million primarily due to higher SPP margins.

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

- **Other Operation and Maintenance** expenses increased $17 million primarily due to the following:
  - A $7 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $3 million increase in general and administrative expenses.
  - A $3 million increase in generation plant expenses.
  - A $2 million increase in energy efficiency program expenses.
  - A $2 million increase in distribution expenses primarily due to increased vegetation management expenses.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to increased environmental and transmission projects.
- **Income Tax Expense** increased $6 million primarily due to an increase in pretax book income and by the recording of federal and state income tax adjustments, partially offset by the regulatory accounting treatment of state income taxes and by other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2014	$	127
Changes in Gross Margin:		
Retail Margins (a)		96
Off-system Sales		(8)
Transmission Revenues		4
Other Revenues		(2)
Total Change in Gross Margin		90
Changes in Expenses and Other:		
Other Operation and Maintenance		(15)
Depreciation and Amortization		(5)
Taxes Other Than Income Taxes		(3)
Interest Income		1
Allowance For Equity Funds Used During Construction		11
Interest Expense		4
Total Change in Expenses and Other		(7)
Income Tax Expense		(25)
Nine Months Ended September 30, 2015	$	185

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

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

- **Retail Margins** increased $96 million primarily due to the following:
  - A $45 million increase primarily due to revenue increases from rate riders in Louisiana and Texas.
  - A $26 million increase in municipal and cooperative revenues primarily due to formula rate adjustments.
  - A $22 million net increase in weather-related usage primarily due to a 16% increase in cooling degree days, partially offset by a decrease in heating degree days.
  - A $16 million increase primarily due to higher fuel cost recovery.

  These increases were partially offset by:
  - A $13 million decrease primarily due to lower weather-normalized retail sales.
- **Margins from Off-system Sales** decreased $8 million primarily due to lower market prices.
- **Transmission Revenues** increased $4 million primarily due to higher SPP margins.

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

- **Other Operation and Maintenance** expenses increased $15 million primarily due to the following:
  - An $8 million increase in SPP transmission services.
  - A $7 million increase in distribution expenses primarily due to increased vegetation management expenses.
- **Depreciation and Amortization** expenses increased $5 million primarily due to a higher depreciable base.
- **Allowance for Equity Funds Used During Construction** increased $11 million primarily due to increased environmental and transmission projects.

- **Interest Expense** decreased $4 million primarily due to the following:
  - A $6 million increase in the debt component of AFUDC due to increased environmental and transmission projects.

  This decrease was partially offset by:
  - A $4 million increase due to increased long-term debt outstanding.
- **Income Tax Expense** increased $25 million primarily due to an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2014 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the "Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 256 for a discussion of accounting pronouncements.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUES				
Electric Generation, Transmission and Distribution	$ 525,922	$ 526,047	$ 1,387,644	$ 1,397,326
Sales to AEP Affiliates	5,959	5,203	13,115	22,748
Other Revenues	618	521	1,486	1,570
TOTAL REVENUES	532,499	531,771	1,402,245	1,421,644
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	179,995	194,175	463,092	500,878
Purchased Electricity for Resale	23,597	36,960	70,799	138,380
Purchased Electricity from AEP Affiliates	—	—	—	3,766
Other Operation	81,391	68,601	214,835	206,442
Maintenance	34,425	29,867	100,076	93,946
Depreciation and Amortization	48,862	46,791	143,780	138,316
Taxes Other Than Income Taxes	23,014	22,246	66,062	63,272
TOTAL EXPENSES	391,284	398,640	1,058,644	1,145,000
OPERATING INCOME	141,215	133,131	343,601	276,644
Other Income (Expense):				
Interest Income	69	230	1,233	322
Allowance for Equity Funds Used During Construction	7,053	3,137	18,164	7,415
Interest Expense	(29,263)	(31,644)	(91,423)	(95,258)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	119,074	104,854	271,575	189,123
Income Tax Expense	37,358	31,042	85,417	60,252
Equity Earnings of Unconsolidated Subsidiary	410	735	2,131	1,461
NET INCOME	82,126	74,547	188,289	130,332
Net Income Attributable to Noncontrolling Interest	1,013	1,109	3,002	3,337
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 81,113	$ 73,438	$ 185,287	$ 126,995

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	**2014**	**2015**	**2014**
Net Income	$ 82,126	$ 74,547	$ 188,289	$ 130,332
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $232 and $305 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $843 and $881 for the Nine Months Ended September 30, 2015 and 2014, Respectively	432	567	1,566	1,636
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $129 and $126 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $387 and $379 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(240)	(235)	(719)	(704)
TOTAL OTHER COMPREHENSIVE INCOME	192	332	847	932
TOTAL COMPREHENSIVE INCOME	82,318	74,879	189,136	131,264
Total Comprehensive Income Attributable to Noncontrolling Interest	1,013	1,109	3,002	3,337
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 81,305	$ 73,770	$ 186,134	$ 127,927

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY - DECEMBER 31, 2013	$ 135,660	$ 674,606	$ 1,253,617	$ (8,444)	$ 478	$ 2,055,917
Common Stock Dividends			(75,000)			(75,000)
Common Stock Dividends – Nonaffiliated					(3,483)	(3,483)
Net Income			126,995		3,337	130,332
Other Comprehensive Income				932		932
TOTAL EQUITY - SEPTEMBER 30, 2014	$ 135,660	$ 674,606	$ 1,305,612	$ (7,512)	$ 332	$ 2,108,698
TOTAL EQUITY - DECEMBER 31, 2014	$ 135,660	$ 674,606	$ 1,293,986	$ (7,466)	$ 415	$ 2,097,201
Common Stock Dividends			(90,000)			(90,000)
Common Stock Dividends – Nonaffiliated					(3,099)	(3,099)
Net Income			185,287		3,002	188,289
Other Comprehensive Income				847		847
Contribution of Mutual Energy SWEPCo, LLC from Parent		1,945				1,945
TOTAL EQUITY - SEPTEMBER 30, 2015	$ 135,660	$ 676,551	$ 1,389,273	$ (6,619)	$ 318	$ 2,195,183

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents (September 30, 2015 and December 31, 2014 Amounts Include $11,693 and $12,695, Respectively, Related to Sabine)	$ 14,258	$ 14,356
Advances to Affiliates	45,019	41,033
Accounts Receivable:		
Customers	41,086	46,738
Affiliated Companies	33,937	37,114
Miscellaneous	31,322	25,625
Allowance for Uncollectible Accounts	(148)	(516)
Total Accounts Receivable	106,197	108,961
Fuel (September 30, 2015 and December 31, 2014 Amounts Include $27,194 and $38,920, Respectively, Related to Sabine)	93,125	116,955
Materials and Supplies	72,735	73,666
Risk Management Assets	1,280	31
Deferred Income Tax Benefits	7,406	9,041
Accrued Tax Benefits	1,413	15,408
Regulatory Asset for Under-Recovered Fuel Costs	14,352	24,024
Prepayments and Other Current Assets	20,083	25,779
TOTAL CURRENT ASSETS	375,868	429,254
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,928,939	3,864,543
Transmission	1,362,543	1,300,729
Distribution	1,945,074	1,894,572
Other Property, Plant and Equipment (Including Plant to be Retired) (September 30, 2015 and December 31, 2014 Amounts Include $291,896 and $288,183, Respectively, Related to Sabine)	895,958	878,753
Construction Work in Progress	681,991	471,980
Total Property, Plant and Equipment	8,814,505	8,410,577
Accumulated Depreciation and Amortization (September 30, 2015 and December 31, 2014 Amounts Include $153,400 and $142,983, Respectively, Related to Sabine)	2,611,129	2,503,290
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,203,376	5,907,287
OTHER NONCURRENT ASSETS		
Regulatory Assets	413,434	393,602
Employee Benefits and Pension Assets	23,437	21,427
Deferred Charges and Other Noncurrent Assets	85,491	65,323
TOTAL OTHER NONCURRENT ASSETS	522,362	480,352
TOTAL ASSETS	$ 7,101,606	$ 6,816,893

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2015 and December 31, 2014
(Unaudited)

	September 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 160,885	$ 175,109
Affiliated Companies	58,866	67,410
Long-term Debt Due Within One Year – Nonaffiliated	3,250	306,750
Risk Management Liabilities	1,302	1,082
Customer Deposits	60,594	59,903
Accrued Taxes	83,125	43,965
Accrued Interest	23,097	44,328
Obligations Under Capital Leases	22,081	17,557
Other Current Liabilities	81,965	104,553
TOTAL CURRENT LIABILITIES	495,165	820,657
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,280,716	1,833,687
Long-term Risk Management Liabilities	757	—
Deferred Income Taxes	1,415,833	1,351,111
Regulatory Liabilities and Deferred Investment Tax Credits	457,438	458,530
Asset Retirement Obligations	108,093	92,015
Employee Benefits and Pension Obligations	26,224	25,374
Obligations Under Capital Leases	74,533	91,044
Deferred Credits and Other Noncurrent Liabilities	47,664	47,274
TOTAL NONCURRENT LIABILITIES	4,411,258	3,899,035
TOTAL LIABILITIES	4,906,423	4,719,692
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	135,660	135,660
Paid-in Capital	676,551	674,606
Retained Earnings	1,389,273	1,293,986
Accumulated Other Comprehensive Income (Loss)	(6,619)	(7,466)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,194,865	2,096,786
Noncontrolling Interest	318	415
TOTAL EQUITY	2,195,183	2,097,201
TOTAL LIABILITIES AND EQUITY	$ 7,101,606	$ 6,816,893

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 188,289	$ 130,332
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	143,780	138,316
Deferred Income Taxes	45,672	181,482
Allowance for Equity Funds Used During Construction	(18,164)	(7,415)
Mark-to-Market of Risk Management Contracts	(272)	802
Pension Contributions to Qualified Plan Trust	(8,052)	(3,832)
Property Taxes	(13,024)	(12,503)
Fuel Over/Under-Recovery, Net	11,705	(19,547)
Change in Other Noncurrent Assets	2,756	11,926
Change in Other Noncurrent Liabilities	(1,820)	39
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2,764	36,622
Fuel, Materials and Supplies	24,761	22,500
Accounts Payable	(17,120)	(15,046)
Accrued Taxes, Net	53,155	(76,982)
Accrued Interest	(21,231)	(24,406)
Other Current Assets	2,794	(7,448)
Other Current Liabilities	(23,678)	(2,983)
Net Cash Flows from Operating Activities	372,315	351,857
INVESTING ACTIVITIES		
Construction Expenditures	(408,293)	(351,666)
Change in Advances to Affiliates, Net	(2,038)	—
Other Investing Activities	4,427	4,334
Net Cash Flows Used for Investing Activities	(405,904)	(347,332)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	445,949	99,633
Change in Advances from Affiliates, Net	—	(2,851)
Retirement of Long-term Debt – Nonaffiliated	(306,750)	(3,250)
Principal Payments for Capital Lease Obligations	(13,398)	(13,673)
Dividends Paid on Common Stock	(90,000)	(75,000)
Dividends Paid on Common Stock – Nonaffiliated	(3,099)	(3,483)
Other Financing Activities	789	844
Net Cash Flows from Financing Activities	33,491	2,220
Net Increase (Decrease) in Cash and Cash Equivalents	(98)	6,745
Cash and Cash Equivalents at Beginning of Period	14,356	17,241
Cash and Cash Equivalents at End of Period	$ 14,258	$ 23,986
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 106,078	$ 113,137
Net Cash Paid (Received) for Income Taxes	12,320	(13,820)
Noncash Acquisitions Under Capital Leases	1,493	3,923
Construction Expenditures Included in Current Liabilities as of September 30,	85,268	88,291
Noncash Contribution of Mutual Energy SWEPCo, LLC from Parent	(1,945)	—
Noncash Increase in Advances to Affiliates, Net due to Contribution of Mutual Energy SWEPCo, LLC	1,948	—

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to SWEPCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1. SIGNIFICANT ACCOUNTING MATTERS

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 Subsidiary. Net income for the three and nine months ended September 30, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed financial statements are unaudited and should be read in conjunction with the audited 2014 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K as filed with the SEC on February 20, 2015.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following final pronouncements will impact the financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management adopted ASU 2014-08 effective January 1, 2015. There were no events requiring the application of this new accounting guidance.

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. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" (ASU 2015-01)

In January 2015, the FASB issued ASU 2015-01 eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. Management plans to adopt ASU 2015-01 effective January 1, 2016.

ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 simplifying the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. The Registrant Subsidiaries include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Form 10-K.

ASU 2015-05 "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement" (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management 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 2015-05 effective January 1, 2016.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 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 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 2015-11 effective January 1, 2017.

ASU 2015-13 "Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets" (ASU 2015-13)

In August 2015, the FASB issued ASU 2015-13 clarifying whether a contract for the purchase or sale of electricity on a forward basis should be eligible to meet the physical delivery criterion of the normal purchases and normal sales scope exception when either the delivery location is within a nodal energy market or the contract necessitates transmission through a nodal energy market and one of the contracting parties incurs charges (or credits) for the transmission of electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. Under the new standard, the use of locational marginal pricing by an independent system operator does not cause a contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. As a result, an entity may elect to designate that contract as a normal purchase or normal sale.

The new accounting guidance is effective upon issuance and applied prospectively. Management has analyzed the impact of this new standard and determined that it will have no impact on the accounting of the Registrant Subsidiaries' contracts. Additionally, adoption has no impact on net income. Management adopted ASU 2015-13 upon its issuance date.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2015 and 2014. All amounts in the following tables are presented net of related income taxes.

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2015	$ —	$ 4,027	$ 220	$ 4,247
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	(222)	(458)	(680)
Net Current Period Other Comprehensive Loss	—	(222)	(458)	(680)
Balance in AOCI as of September 30, 2015	$ —	$ 3,805	$ (238)	$ 3,567

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2014	$ —	$ 3,596	$ (899)	$ 2,697
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	170	(333)	(163)
Net Current Period Other Comprehensive Income (Loss)	—	170	(333)	(163)
Balance in AOCI as of September 30, 2014	$ —	$ 3,766	$ (1,232)	$ 2,534

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2014	$ —	$ 3,896	$ 1,136	$ 5,032
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	(91)	(1,374)	(1,465)
Net Current Period Other Comprehensive Loss	—	(91)	(1,374)	(1,465)
Balance in AOCI as of September 30, 2015	$ —	$ 3,805	$ (238)	$ 3,567

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2013	$ 94	$ 3,090	$ (233)	$ 2,951
Change in Fair Value Recognized in AOCI	1,686	—	—	1,686
Amounts Reclassified from AOCI	(1,780)	676	(999)	(2,103)
Net Current Period Other Comprehensive Income (Loss)	(94)	676	(999)	(417)
Balance in AOCI as of September 30, 2014	$ —	$ 3,766	$ (1,232)	$ 2,534

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of June 30, 2015	$ —	$ (13,871)	$ 68	$ (13,803)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	267	11	278
Net Current Period Other Comprehensive Income	—	267	11	278
Balance in AOCI as of September 30, 2015	$ —	$ (13,604)	$ 79	$ (13,525)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of June 30, 2014	$ —	$ (15,155)	$ 507	$ (14,648)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	410	42	452
Net Current Period Other Comprehensive Income	—	410	42	452
Balance in AOCI as of September 30, 2014	$ —	$ (14,745)	$ 549	$ (14,196)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2014	$ —	$ (14,406)	$ 46	$ (14,360)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	802	33	835
Net Current Period Other Comprehensive Income	—	802	33	835
Balance in AOCI as of September 30, 2015	$ —	$ (13,604)	$ 79	$ (13,525)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$ 46	$ (15,976)	$ 421	$ (15,509)
Change in Fair Value Recognized in AOCI	1,130	—	—	1,130
Amounts Reclassified from AOCI	(1,176)	1,231	128	183
Net Current Period Other Comprehensive Income (Loss)	(46)	1,231	128	1,313
Balance in AOCI as of September 30, 2014	$ —	$ (14,745)	$ 549	$ (14,196)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges		
	Commodity	*Interest Rate and* Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of June 30, 2015	$ —	$ 4,916	$ 4,916
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(344)	(344)
Net Current Period Other Comprehensive Loss	—	(344)	(344)
Balance in AOCI as of September 30, 2015	$ —	$ 4,572	$ 4,572

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of June 30, 2014	$ —	$ 6,288	$ 6,288
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(343)	(343)
Net Current Period Other Comprehensive Loss	—	(343)	(343)
Balance in AOCI as of September 30, 2014	$ —	$ 5,945	$ 5,945

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2014	$ —	$ 5,602	$ 5,602
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(1,030)	(1,030)
Net Current Period Other Comprehensive Loss	—	(1,030)	(1,030)
Balance in AOCI as of September 30, 2015	$ —	$ 4,572	$ 4,572

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2013	$ 105	$ 6,974	$ 7,079
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	(105)	(1,029)	(1,134)
Net Current Period Other Comprehensive Loss	(105)	(1,029)	(1,134)
Balance in AOCI as of September 30, 2014	$ —	$ 5,945	$ 5,945

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	*Total*
		(in thousands)	
Balance in AOCI as of June 30, 2015	$ —	$ 4,563	$ 4,563
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(189)	(189)
Net Current Period Other Comprehensive Loss	—	(189)	(189)
Balance in AOCI as of September 30, 2015	$ —	$ 4,374	$ 4,374

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of June 30, 2014	$ —	$ 5,322	$ 5,322
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(190)	(190)
Net Current Period Other Comprehensive Loss	—	(190)	(190)
Balance in AOCI as of September 30, 2014	$ —	$ 5,132	$ 5,132

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2014	$ —	$ 4,943	$ 4,943
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(569)	(569)
Net Current Period Other Comprehensive Loss	—	(569)	(569)
Balance in AOCI as of September 30, 2015	$ —	$ 4,374	$ 4,374

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2013	$ 57	$ 5,701	$ 5,758
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	(57)	(569)	(626)
Net Current Period Other Comprehensive Loss	(57)	(569)	(626)
Balance in AOCI as of September 30, 2014	$ —	$ 5,132	$ 5,132

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2015	$ —	$ (9,902)	$ 3,091	$ (6,811)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	432	(240)	192
Net Current Period Other Comprehensive Income (Loss)	—	432	(240)	192
Balance in AOCI as of September 30, 2015	$ —	$ (9,470)	$ 2,851	$ (6,619)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2014	$ —	$ (12,169)	$ 4,325	$ (7,844)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	567	(235)	332
Net Current Period Other Comprehensive Income (Loss)	—	567	(235)	332
Balance in AOCI as of September 30, 2014	$ —	$ (11,602)	$ 4,090	$ (7,512)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2014	$ —	$ (11,036)	$ 3,570	$ (7,466)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	1,566	(719)	847
Net Current Period Other Comprehensive Income (Loss)	—	1,566	(719)	847
Balance in AOCI as of September 30, 2015	$ —	$ (9,470)	$ 2,851	$ (6,619)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2013	$ 66	$ (13,304)	$ 4,794	$ (8,444)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	(66)	1,702	(704)	932
Net Current Period Other Comprehensive Income (Loss)	(66)	1,702	(704)	932
Balance in AOCI as of September 30, 2014	$ —	$ (11,602)	$ 4,090	$ (7,512)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ —
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	(342)	262
Subtotal – Interest Rate and Foreign Currency	(342)	262
Reclassifications from AOCI, before Income Tax (Expense) Credit	(342)	262
Income Tax (Expense) Credit	(120)	92
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(222)	170
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(1,282)	(1,281)
Amortization of Actuarial (Gains)/Losses	577	769
Reclassifications from AOCI, before Income Tax (Expense) Credit	(705)	(512)
Income Tax (Expense) Credit	(247)	(179)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(458)	(333)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (680)	$ (163)

APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Nine Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ (526)
Other Operation Expense	—	(10)
Maintenance Expense	—	(20)
Property, Plant and Equipment	—	(17)
Regulatory Assets/(Liabilities), Net (a)	—	(2,165)
Subtotal – Commodity	—	(2,738)
Interest Rate and Foreign Currency:		
Interest Expense	(140)	1,042
Subtotal – Interest Rate and Foreign Currency	(140)	1,042
Reclassifications from AOCI, before Income Tax (Expense) Credit	(140)	(1,696)
Income Tax (Expense) Credit	(49)	(592)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(91)	(1,104)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(3,847)	(3,846)
Amortization of Actuarial (Gains)/Losses	1,733	2,309
Reclassifications from AOCI, before Income Tax (Expense) Credit	(2,114)	(1,537)
Income Tax (Expense) Credit	(740)	(538)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1,374)	(999)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (1,465)	$ (2,103)

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ —
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	412	631
Subtotal – Interest Rate and Foreign Currency	412	631
Reclassifications from AOCI, before Income Tax (Expense) Credit	412	631
Income Tax (Expense) Credit	145	221
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	267	410
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(198)	(200)
Amortization of Actuarial (Gains)/Losses	215	264
Reclassifications from AOCI, before Income Tax (Expense) Credit	17	64
Income Tax (Expense) Credit	6	22
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	11	42
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 278	$ 452

I&M

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Nine Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ (812)
Other Operation Expense	—	(7)
Maintenance Expense	—	(7)
Property, Plant and Equipment	—	(10)
Regulatory Assets/(Liabilities), Net (a)	—	(973)
Subtotal – Commodity	—	(1,809)
Interest Rate and Foreign Currency:		
Interest Expense	1,234	1,893
Subtotal – Interest Rate and Foreign Currency	1,234	1,893
Reclassifications from AOCI, before Income Tax (Expense) Credit	1,234	84
Income Tax (Expense) Credit	432	29
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	802	55
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(596)	(597)
Amortization of Actuarial (Gains)/Losses	647	791
Reclassifications from AOCI, before Income Tax (Expense) Credit	51	194
Income Tax (Expense) Credit	18	66
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	33	128
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 835	$ 183

OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2015 and 2014

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30, 2015	2014
	(in thousands)	
Commodity:		
Other Operation Expense	$ —	$ —
Maintenance Expense	—	—
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Depreciation and Amortization Expense	(4)	(3)
Interest Expense	(526)	(524)
Subtotal – Interest Rate and Foreign Currency	(530)	(527)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(530)	(527)
Income Tax (Expense) Credit	(186)	(184)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (344)	$ (343)

OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30, 2015	2014
	(in thousands)	
Commodity:		
Other Operation Expense	$ —	$ (11)
Maintenance Expense	—	(11)
Property, Plant and Equipment	—	(18)
Regulatory Assets/(Liabilities), Net (a)	—	(122)
Subtotal – Commodity	—	(162)
Interest Rate and Foreign Currency:		
Depreciation and Amortization Expense	(10)	(9)
Interest Expense	(1,574)	(1,572)
Subtotal – Interest Rate and Foreign Currency	(1,584)	(1,581)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,584)	(1,743)
Income Tax (Expense) Credit	(554)	(609)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (1,030)	$ (1,134)

PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2015 and 2014

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30, 2015	2014
	(in thousands)	
Commodity:		
Other Operation Expense	$ —	$ —
Maintenance Expense	—	—
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	(291)	(292)
Subtotal – Interest Rate and Foreign Currency	(291)	(292)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(291)	(292)
Income Tax (Expense) Credit	(102)	(102)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (189)	$ (190)

PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30, 2015	2014
	(in thousands)	
Commodity:		
Other Operation Expense	$ —	$ (8)
Maintenance Expense	—	(9)
Property, Plant and Equipment	—	(13)
Regulatory Assets/(Liabilities), Net (a)	—	(58)
Subtotal – Commodity	—	(88)
Interest Rate and Foreign Currency:		
Interest Expense	(875)	(876)
Subtotal – Interest Rate and Foreign Currency	(875)	(876)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(875)	(964)
Income Tax (Expense) Credit	(306)	(338)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (569)	$ (626)

SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$ —	$ —
Maintenance Expense	—	—
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	665	872
Subtotal – Interest Rate and Foreign Currency	665	872
Reclassifications from AOCI, before Income Tax (Expense) Credit	665	872
Income Tax (Expense) Credit	233	305
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	432	567
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(468)	(478)
Amortization of Actuarial (Gains)/Losses	99	118
Reclassifications from AOCI, before Income Tax (Expense) Credit	(369)	(360)
Income Tax (Expense) Credit	(129)	(125)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(240)	(235)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 192	$ 332

SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Nine Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$ —	$ (13)
Maintenance Expense	—	(10)
Property, Plant and Equipment	—	(11)
Regulatory Assets/(Liabilities), Net (a)	—	(67)
Subtotal – Commodity	—	(101)
Interest Rate and Foreign Currency:		
Interest Expense	2,409	2,616
Subtotal – Interest Rate and Foreign Currency	2,409	2,616
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,409	2,515
Income Tax (Expense) Credit	843	879
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,566	1,636
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(1,402)	(1,433)
Amortization of Actuarial (Gains)/Losses	296	351
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,106)	(1,082)
Income Tax (Expense) Credit	(387)	(378)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(719)	(704)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 847	$ 932

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

4. RATE MATTERS

As discussed in the 2014 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2014 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2015 and updates the 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

	APCo	
Noncurrent Regulatory Assets	**September 30, 2015**	**December 31, 2014**
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Materials and Supplies Related to Retired Plants	$ 8,592	$ —
Vegetation Management Program – West Virginia	—	19,089
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	32,128	—
Peak Demand Reduction/Energy Efficiency – Virginia	11,650	8,791
Amos Plant Transfer Costs – West Virginia	1,950	1,377
Deferred Permit Fees Related to Retired Plants – West Virginia	617	—
Storm Related Costs – West Virginia	—	65,206
Carbon Capture and Storage Product Validation Facility – West Virginia, FERC	—	13,264
IGCC Pre-Construction Costs – West Virginia, FERC	—	10,838
Expanded Net Energy Charge – Coal Inventory – West Virginia	—	3,421
Expanded Net Energy Charge – Construction Surcharge – West Virginia	—	2,307
Carbon Capture and Storage Commercial Scale Facility – West Virginia, FERC	—	1,287
Other Regulatory Assets Pending Final Regulatory Approval	—	168
Total Regulatory Assets Pending Final Regulatory Approval	$ 54,937	$ 125,748

	I&M	
Noncurrent Regulatory Assets	**September 30, 2015**	**December 31, 2014**
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Materials and Supplies Related to Retired Plants	$ 11,652	$ —
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	27,079	—
Cook Plant Turbine	8,955	6,596
Stranded Costs on Abandoned Plants	3,897	3,897
Deferred Cook Plant Life Cycle Management Project Costs – Michigan	3,445	1,222
Rockport Dry Sorbent Injection System	1,865	148
Storm Related Costs – Indiana	—	1,074
Other Regulatory Assets Pending Final Regulatory Approval	11	712
Total Regulatory Assets Pending Final Regulatory Approval	$ 56,904	$ 13,649

Noncurrent Regulatory Assets	OPCo September 30, 2015	OPCo December 31, 2014
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Ormet Special Rate Recovery Mechanism	$ 10,483	$ 10,483
Total Regulatory Assets Pending Final Regulatory Approval	$ 10,483	$ 10,483

Noncurrent Regulatory Assets	PSO September 30, 2015	PSO December 31, 2014
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ —	$ 16,614
Other Regulatory Assets Pending Final Regulatory Approval	—	1,079
Total Regulatory Assets Pending Final Regulatory Approval	$ —	$ 17,693

Noncurrent Regulatory Assets	SWEPCo September 30, 2015	SWEPCo December 31, 2014
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Shipe Road Transmission Project	$ 3,031	$ 2,287
Asset Retirement Obligation	1,516	1,144
Rate Case Expenses	—	8,126
Other Regulatory Assets Pending Final Regulatory Approval	695	558
Total Regulatory Assets Pending Final Regulatory Approval	$ 5,242	$ 12,115

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018.

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

June 2012 – May 2015 ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio, which has scheduled oral arguments for the fourth quarter of 2015.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the May 31, 2015 capacity deferral balance, which was $444 million. In May 2015, the PUCO granted intervenors requests for rehearing. As of September 30, 2015, OPCo's net deferred capacity costs balance of $392 million, including debt carrying costs, was recorded in Regulatory Assets on the condensed balance sheet. Through September 30, 2015, OPCo has collected $183 million in deferred capacity costs, and related carrying charges.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order. Oral arguments at the Supreme Court of Ohio were held in May 2015.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/ MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

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

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.

June 2015 - May 2018 ESP Including PPA Application

In December 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 Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order 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 PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order. In July 2015, intervenors filed appeals with the Supreme Court of Ohio that included opposition to the authorization of a PPA rider and the modifications to a transmission rider.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider. In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) included the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units. A hearing at the PUCO related to the PPA commenced in September 2015. In October 2015, the PUCO staff submitted testimony that opposed the PPA application as currently proposed but concluded that, with changes, a PPA could be in the public interest.

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.

Significantly Excessive Earnings Test Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project. In September 2013, a proposed second phase of OPCo's *gridSMART*® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In June 2015, OPCo submitted its 2014 SEET filing with the PUCO. Management believes its financial statements adequately address the impact of 2014 SEET requirements.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation and transfer of OPCo's generation assets and associated generation liabilities at net book value to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, corporate separation of OPCo's generation assets was completed. If any part of the PUCO order is overturned, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers.

In September 2014, the Supreme Court of Ohio upheld the PUCO order on appeal. A review of the coal reserve valuation by an outside consultant has not been initiated by the PUCO. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

2012 and 2013 Fuel Adjustment Clause Audits

In May 2014, the PUCO-selected outside consultant provided its final report related to its 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. These recommendations are opposed by OPCo. In addition, the PUCO will consider the results of the final audit of the recovery of fixed fuel costs that was issued in October 2014. See the "June 2012 - May 2015 ESP Including Capacity Charge" section above. If the PUCO orders a reduction to the FAC deferral or a refund to customers, it could reduce future net income and cash flows and impact financial condition.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In 2013, Ormet filed for bankruptcy and subsequently shut down operations. In March 2014, the PUCO issued an order in OPCo's Economic Development Rider (EDR) filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of September 30, 2015, is recorded in Regulatory Assets on the condensed balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

In addition, in the 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are not recoverable, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

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. As of September 30, 2015, the net book value of Welsh Plant, Unit 2 was $83 million, before cost of removal, including materials and supplies inventory and CWIP.

Upon rehearing in January 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 March 2014, the PUCT issued an order related to the January 2014 PUCT ruling and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

If certain parts of the PUCT order are overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs and potential fuel or replacement power disallowances related to Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC review base rates in 2014 and 2015 and that SWEPCo recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition.

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchased power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015. These increases are subject to LPSC staff review and are subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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.

Welsh Plant, Units 1 and 3 – Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2024 for Welsh Plant, Units 1 and 3 will cost approximately $700 million, excluding AFUDC. As of September 30, 2015, SWEPCo has incurred costs of $303 million, including AFUDC, and has remaining contractual construction obligations of $62 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. As of September 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $529 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo Rate Matters

2014 West Virginia Base Rate Case

In May 2015, the WVPSC issued an order on APCo's base rate case. Upon implementation of the order in May 2015, and consistent with the WVPSC authorized total revenue, annual base rates were authorized to be increased by $85 million based upon a 9.75% return on common equity. The order included a delayed billing of $22 million of the annual base rate increase to residential customers until July 2016. The order provided for carrying charges based upon a WACC rate for the $22 million delayed billing through June 2016, and stated recovery would be addressed in the next ENEC case scheduled for 2016. Additionally, the order included approval of (a) an initial vegetation management rider of $38 million annually, (b) revised deprecation rates, including recovery of plants to be retired and (c) the recovery of $77 million in previously recorded regulatory assets, which will predominantly be recovered over five years.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a proceeding to address the proper treatment of APCo's authorized regulatory assets. In February and March 2015, briefs related to this proceeding were filed by various parties. As of September 30, 2015, APCo's authorized regulatory assets under review in this proceeding were $11 million. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

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

PSO Rate Matters

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan for the Federal EPA's Regional Haze Rule and Mercury and Air Toxics Standards, and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 of Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% to be effective in January 2016, except for the $44 million for environmental investments, which is effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. The total estimated cost of the environmental controls to be installed at Northeastern Plant, Unit 3 and the Comanche Plant is $219 million, excluding AFUDC. As of September 30, 2015, PSO has incurred costs of $162 million related to these projects, including AFUDC.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC. As of September 30, 2015, the net book value of Northeastern Plant, Unit 4 was $94 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO's investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, certain intervenors did not support an increase in depreciation expense for the Northeastern Plant, Units 3 and 4 to permit cost recovery by Unit 3's 2026 retirement date as the proposals called for no change in existing cost recovery by 2040. Hearings at the OCC are scheduled for December 2015.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2014 Oklahoma Base Rate Case

In April 2015, the OCC issued an order that approved a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors. The approved stipulation provides for no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider provides $24 million of revenues over 14 months beginning in November 2014 and increases to $27 million in 2016. The stipulation also included (a) new depreciation rates for advanced metering investments and existing meters, also effective November 2014, (b) a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component and (c) recovery of regulatory assets for 2013 storms and regulatory case expenses. The advanced metering cost rider was implemented in November 2014.

I&M Rate Matters

Tanners Creek Plant

In October 2014, I&M filed an application with the IURC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant. Upon retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant. The new depreciation rates would result in a decrease in I&M's Indiana jurisdictional electric depreciation expense which I&M proposed to reduce customer rates through a credit rider. In May 2015, the IURC issued an order approving I&M's request for revised depreciation rates.

In May 2015, Tanners Creek Plant was retired. Upon retirement, $265 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Tanners Creek Plant and is being amortized over 29 years. An additional $38 million was reclassified as Regulatory Assets on the condensed balance sheet for related asset retirement obligations and materials and supplies, which are currently not being amortized, pending regulatory approval.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M's seven-year TDSIC Plan for eligible transmission, distribution and storage system improvements totaling $787 million. In April 2015, I&M filed a notice with the IURC to exclude $117 million related to certain projects. In September 2015, the IURC granted I&M's motion to withdraw its application for reconsideration and/or rehearing and I&M withdrew its appeal with the Indiana Court of Appeals.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Contingent liabilities are accrued 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 determined that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, such contingencies and the possible loss or range of loss are disclosed 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 the 2014 Annual Report 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 – Affecting APCo, I&M and OPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two revolving credit facilities totaling $3.5 billion, under which up to $1.2 billion may be issued as letters of credit. As of September 30, 2015, the maximum future payment for letters of credit issued under the revolving credit facilities was as follows:

Company	Amount	Maturity
	(in thousands)	
I&M	$ 35	March 2016

AEP issues letters of credit under two uncommitted facilities totaling $150 million. An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. As of September 30, 2015, the maximum future payment for letters of credit issued under the uncommitted facilities was as follows:

Company	Amount	Maturity
	(in thousands)	
OPCo	$ 4,200	September 2016

The Registrant Subsidiaries have $307 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $310 million as follows:

Company	Pollution Control Bonds	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
	(in thousands)		
APCo	$ 229,650	$ 232,293	March 2016 to March 2017
I&M	77,000	77,886	March 2017

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of September 30, 2015, SWEPCo has collected $65 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $49 million is recorded in Asset Retirement Obligations on SWEPCo's condensed balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries 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, 2015, 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 Registrant Subsidiaries 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 Registrant Subsidiaries 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, 2015, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss
	(in thousands)
APCo	$ 5,396
I&M	3,448
OPCo	6,075
PSO	2,785
SWEPCo	3,086

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $11 million and $12 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2015.

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% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are $9 million and $10 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

ENVIRONMENTAL CONTINGENCIES

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting I&M

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 Registrant Subsidiaries 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 for all of these sites was reduced. As of September 30, 2015, I&M's accrual for all of these sites is approximately $8 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 – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. 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.

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation – Affecting 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 plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, 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. Plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. Management will continue to defend against the remaining claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Wage and Hours Lawsuit – Affecting PSO

In August 2013, PSO received an amended complaint filed in the U.S. District Court for the Northern District of Oklahoma by 36 current and former line and warehouse employees alleging that they have been denied overtime pay in violation of the Fair Labor Standards Act. Plaintiffs claim that they are entitled to overtime pay for "on call" time. They allege that restrictions placed on them during on call hours are burdensome enough that they are entitled to compensation for these hours as hours worked. Plaintiffs also filed a motion to conditionally certify this action as a class action, claiming there are an additional 70 individuals similarly situated to plaintiffs. Plaintiffs seek damages in the amount of unpaid overtime over a three-year period and liquidated damages in the same amount.

In March 2014, the federal court granted plaintiffs' motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. Two plaintiffs have since dismissed their claims without prejudice, leaving 78 plaintiffs. Management will continue to defend the case. Management does not believe a loss is probable. If there is an unfavorable outcome contrary to expectations, management estimates possible losses of up to $30 million.

Gavin Landfill Litigation – Affecting 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. 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. Eleven of the family members are pursuing personal injury/illness 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, management filed a motion to dismiss the complaint, contending the case should be filed in Ohio. In August 2015, the court denied the motion. Management appealed that decision to the West Virginia Supreme Court. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

6. BENEFIT PLANS

The Registrant Subsidiaries participate in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. The Registrant Subsidiaries also participate in OPEB plans sponsored by AEP 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 Subsidiary for the plans for the three and nine months ended September 30, 2015 and 2014:

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 2,175	$ 1,759	$ 286	$ 362
Interest Cost	6,679	7,406	2,584	3,197
Expected Return on Plan Assets	(8,745)	(8,482)	(4,529)	(4,634)
Amortization of Prior Service Cost (Credit)	45	49	(2,513)	(2,512)
Amortization of Net Actuarial Loss	3,474	4,149	900	1,145
Net Periodic Benefit Cost (Credit)	$ 3,628	$ 4,881	$ (3,272)	$ (2,442)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 6,525	$ 5,277	$ 857	$ 1,086
Interest Cost	20,037	22,218	7,753	9,591
Expected Return on Plan Assets	(26,236)	(25,445)	(13,587)	(13,900)
Amortization of Prior Service Cost (Credit)	135	148	(7,538)	(7,537)
Amortization of Net Actuarial Loss	10,421	12,445	2,699	3,436
Net Periodic Benefit Cost (Credit)	$ 10,882	$ 14,643	$ (9,816)	$ (7,324)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 3,217	$ 2,517	$ 406	$ 486
Interest Cost	6,114	6,573	1,592	1,909
Expected Return on Plan Assets	(8,115)	(7,749)	(3,304)	(3,363)
Amortization of Prior Service Cost (Credit)	45	49	(2,355)	(2,355)
Amortization of Net Actuarial Loss	3,145	3,647	506	592
Net Periodic Benefit Cost (Credit)	$ 4,406	$ 5,037	$ (3,155)	$ (2,731)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 9,651	$ 7,551	$ 1,219	$ 1,460
Interest Cost	18,344	19,720	4,776	5,728
Expected Return on Plan Assets	(24,347)	(23,245)	(9,912)	(10,090)
Amortization of Prior Service Cost (Credit)	136	146	(7,066)	(7,066)
Amortization of Net Actuarial Loss	9,434	10,939	1,519	1,776
Net Periodic Benefit Cost (Credit)	$ 13,218	$ 15,111	$ (9,464)	$ (8,192)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 1,671	$ 1,285	$ 216	$ 256
Interest Cost	5,071	5,527	1,615	1,900
Expected Return on Plan Assets	(6,878)	(6,607)	(3,376)	(3,379)
Amortization of Prior Service Cost (Credit)	35	40	(1,731)	(1,731)
Amortization of Net Actuarial Loss	2,644	3,105	517	595
Net Periodic Benefit Cost (Credit)	$ 2,543	$ 3,350	$ (2,759)	$ (2,359)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 5,015	$ 3,855	$ 647	$ 769
Interest Cost	15,211	16,579	4,845	5,701
Expected Return on Plan Assets	(20,634)	(19,820)	(10,130)	(10,139)
Amortization of Prior Service Cost (Credit)	105	118	(5,192)	(5,192)
Amortization of Net Actuarial Loss	7,932	9,316	1,552	1,785
Net Periodic Benefit Cost (Credit)	$ 7,629	$ 10,048	$ (8,278)	$ (7,076)

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 1,598	$ 1,301	$ 170	$ 209
Interest Cost	2,731	3,015	759	893
Expected Return on Plan Assets	(3,786)	(3,651)	(1,578)	(1,575)
Amortization of Prior Service Cost (Credit)	63	74	(1,072)	(1,072)
Amortization of Net Actuarial Loss	1,418	1,689	242	278
Net Periodic Benefit Cost (Credit)	$ 2,024	$ 2,428	$ (1,479)	$ (1,267)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 4,796	$ 3,905	$ 509	$ 629
Interest Cost	8,194	9,043	2,277	2,680
Expected Return on Plan Assets	(11,358)	(10,953)	(4,732)	(4,725)
Amortization of Prior Service Cost (Credit)	189	222	(3,217)	(3,217)
Amortization of Net Actuarial Loss	4,252	5,065	725	832
Net Periodic Benefit Cost (Credit)	$ 6,073	$ 7,282	$ (4,438)	$ (3,801)

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 2,081	$ 1,655	$ 211	$ 253
Interest Cost	2,932	3,163	837	998
Expected Return on Plan Assets	(4,008)	(3,857)	(1,735)	(1,754)
Amortization of Prior Service Cost (Credit)	78	87	(1,289)	(1,289)
Amortization of Net Actuarial Loss	1,506	1,762	266	309
Net Periodic Benefit Cost (Credit)	$ 2,589	$ 2,810	$ (1,710)	$ (1,483)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 6,244	$ 4,964	$ 632	$ 759
Interest Cost	8,796	9,488	2,512	2,994
Expected Return on Plan Assets	(12,024)	(11,571)	(5,206)	(5,262)
Amortization of Prior Service Cost (Credit)	232	262	(3,867)	(3,867)
Amortization of Net Actuarial Loss	4,520	5,285	798	926
Net Periodic Benefit Cost (Credit)	$ 7,768	$ 8,428	$ (5,131)	$ (4,450)

7. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business, except OPCo, an electricity transmission and distribution business that started in 2014. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and participants in the wholesale electricity, natural gas, coal and emission allowance markets. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrant Subsidiaries due to changes in the underlying market prices or rates. AEPSC, on behalf of the Registrant Subsidiaries, manages these risks using derivative instruments.

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, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of the Registrant Subsidiaries. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs 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.

AEPSC, on behalf of the Registrant Subsidiaries, enters into power, 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. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the Registrant Subsidiaries' commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of the Registrant Subsidiaries, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of September 30, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments
September 30, 2015

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWhs	62,306	30,345	13,470	17,580	21,736
Coal	Tons	116	1,468	—	—	2,125
Natural Gas	MMBtus	256	174	—	—	—
Heating Oil and Gasoline	Gallons	1,763	836	1,858	1,019	1,166
Interest Rate	USD	$ 2,645	$ 1,794	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2014

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWhs	32,479	23,774	20,334	16,765	20,469
Coal	Tons	279	500	—	—	1,500
Natural Gas	MMBtus	421	286	—	—	—
Heating Oil and Gasoline	Gallons	1,089	521	1,108	614	699
Interest Rate	USD	$ 5,094	$ 3,455	$ —	$ —	$ —

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges 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 Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries 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, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrant Subsidiaries 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 condensed balance sheet 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 Registrant Subsidiaries also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with 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 Registrant Subsidiaries 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 Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2015 and December 31, 2014 condensed balance sheets, the Registrant Subsidiaries 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, 2015		December 31, 2014	
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 thousands)		
APCo	$ —	$ 1,688	$ 68	$ 98
I&M	—	333	163	47
OPCo	—	500	—	102
PSO	—	280	—	54
SWEPCo	—	319	—	62

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the condensed balance sheets as of September 30, 2015 and December 31, 2014:

APCo

Fair Value of Derivative Instruments
September 30, 2015

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 34,278	$ —	$ —	$ 34,278	$ (6,928)	$ 27,350
Long-term Risk Management Assets - Nonaffiliated	2,485	—	—	2,485	(450)	2,035
Total Assets	36,763	—	—	36,763	(7,378)	29,385
Current Risk Management Liabilities - Nonaffiliated	15,345	—	—	15,345	(8,443)	6,902
Long-term Risk Management Liabilities - Nonaffiliated	1,596	—	—	1,596	(623)	973
Total Liabilities	16,941	—	—	16,941	(9,066)	7,875
Total MTM Derivative Contract Net Assets (Liabilities)	$ 19,822	$ —	$ —	$ 19,822	$ 1,688	$ 21,510

APCo

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets - Nonaffiliated	$ 32,903	$ —	$ —	$ 32,903	$ (9,111)	$ 23,792
Long-term Risk Management Assets - Nonaffiliated	5,159	—	—	5,159	(268)	4,891
Total Assets	38,062	—	—	38,062	(9,379)	28,683
Current Risk Management Liabilities - Non Affiliated	20,161	—	—	20,161	(9,144)	11,017
Long-term Risk Management Liabilities - Nonaffiliated	2,322	—	—	2,322	(265)	2,057
Total Liabilities	22,483	—	—	22,483	(9,409)	13,074
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,579	$ —	$ —	$ 15,579	$ 30	$ 15,609

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(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.

I&M

Fair Value of Derivative Instruments
September 30, 2015

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 16,675	$ —	$ —	$ 16,675	$ (6,048)	$ 10,627
Long-term Risk Management Assets - Nonaffiliated	1,619	—	—	1,619	(281)	1,338
Total Assets	18,294	—	—	18,294	(6,329)	11,965
Current Risk Management Liabilities - Nonaffiliated	10,901	—	—	10,901	(6,286)	4,615
Long-term Risk Management Liabilities - Nonaffiliated	1,624	—	—	1,624	(376)	1,248
Total Liabilities	12,525	—	—	12,525	(6,662)	5,863
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5,769	$ —	$ —	$ 5,769	$ 333	$ 6,102

I&M

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets - Nonaffiliated	$ 28,545	$ —	$ —	$ 28,545	$ (6,217)	$ 22,328
Long-term Risk Management Assets - Nonaffiliated	3,499	—	—	3,499	(182)	3,317
Total Assets	32,044	—	—	32,044	(6,399)	25,645
Current Risk Management Liabilities - Nonaffiliated	11,326	—	—	11,326	(6,103)	5,223
Long-term Risk Management Liabilities - Nonaffiliated	1,575	—	—	1,575	(180)	1,395
Total Liabilities	12,901	—	—	12,901	(6,283)	6,618
Total MTM Derivative Contract Net Assets (Liabilities)	$ 19,143	$ —	$ —	$ 19,143	$ (116)	$ 19,027

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(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.

OPCo

Fair Value of Derivative Instruments
September 30, 2015

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts *Interest Rate and Foreign Currency (a)*	Gross Amounts of Risk Management *Assets/* Liabilities Recognized	Gross Amounts Offset in the *Statement of* Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the *Statement of* Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ —	$ —	$ —	$ —	$ —	$ —
Long-term Risk Management Assets	23,265	—	—	23,265	—	23,265
Total Assets	23,265	—	—	23,265	—	23,265
Current Risk Management Liabilities	3,271	—	—	3,271	(448)	2,823
Long-term Risk Management Liabilities	4,923	—	—	4,923	(52)	4,871
Total Liabilities	8,194	—	—	8,194	(500)	7,694
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,071	$ —	$ —	$ 15,071	$ 500	$ 15,571

OPCo

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ *Liabilities* Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of *Assets/Liabilities* Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 7,242	$ —	$ —	$ 7,242	$ —	$ 7,242
Long-term Risk Management Assets	45,102	—	—	45,102	—	45,102
Total Assets	52,344	—	—	52,344	—	52,344
Current Risk Management Liabilities	2,045	—	—	2,045	(102)	1,943
Long-term Risk Management Liabilities	3,013	—	—	3,013	—	3,013
Total Liabilities	5,058	—	—	5,058	(102)	4,956
Total MTM Derivative Contract *Net Assets (Liabilities)*	$ 47,286	$ —	$ —	$ 47,286	$ 102	$ 47,388

(a) *Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on* the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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.

PSO

Fair Value of Derivative Instruments
September 30, 2015

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 and Foreign Currency (a)			
			(in thousands)			
Current Risk Management Assets	$ 1,166	$ —	$ —	$ 1,166	$ (131)	$ 1,035
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	1,166	—	—	1,166	(131)	1,035
Current Risk Management Liabilities	454	—	—	454	(384)	70
Long-term Risk Management Liabilities	35	—	—	35	(27)	8
Total Liabilities	489	—	—	489	(411)	78
Total MTM Derivative Contract Net Assets (Liabilities)	$ 677	$ —	$ —	$ 677	$ 280	$ 957

PSO

Fair Value of Derivative Instruments
December 31, 2014

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 and Foreign Currency (a)			
			(in thousands)			
Current Risk Management Assets	$ 360	$ —	$ —	$ 360	$ (360)	$ —
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	360	—	—	360	(360)	—
Current Risk Management Liabilities	1,332	—	—	1,332	(414)	918
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	1,332	—	—	1,332	(414)	918
Total MTM Derivative Contract Net Assets (Liabilities)	$ (972)	$ —	$ —	$ (972)	$ 54	$ (918)

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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.

SWEPCo

Fair Value of Derivative Instruments
September 30, 2015

	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)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**			
			(in thousands)			
Current Risk Management Assets	$ 1,442	$ —	$ —	$ 1,442	$ (162)	$ 1,280
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	1,442	—	—	1,442	(162)	1,280
Current Risk Management Liabilities	1,752	—	—	1,752	(450)	1,302
Long-term Risk Management Liabilities	788	—	—	788	(31)	757
Total Liabilities	2,540	—	—	2,540	(481)	2,059
Total MTM Derivative Contract Net Assets (Liabilities)	$ (1,098)	$ —	$ —	$ (1,098)	$ 319	$ (779)

SWEPCo

Fair Value of Derivative Instruments
December 31, 2014

	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)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**			
			(in thousands)			
Current Risk Management Assets	$ 471	$ —	$ —	$ 471	$ (440)	$ 31
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	471	—	—	471	(440)	31
Current Risk Management Liabilities	1,584	—	—	1,584	(502)	1,082
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	1,584	—	—	1,584	(502)	1,082
Total MTM Derivative Contract Net Assets (Liabilities)	$ (1,113)	$ —	$ —	$ (1,113)	$ 62	$ (1,051)

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(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 Registrant Subsidiaries' activity of derivative risk management contracts for the three and nine months ended September 30, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2015

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ (369)	$ 350	$ (917)	$ (9)	$ (7)
Sales to AEP Affiliates	1,156	3,336	—	—	—
Other Operation Expense	(88)	(63)	(128)	(109)	(127)
Maintenance Expense	(164)	(86)	(140)	(88)	(88)
Purchased Electricity for Resale	831	15	30	—	—
Regulatory Assets (a)	861	(981)	—	(190)	188
Regulatory Liabilities (a)	3,197	(1,718)	(22,281)	(498)	1,137
Total Gain (Loss) on Risk Management Contracts	$ 5,424	$ 853	$ (23,436)	$ (894)	$ 1,103

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2014

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 1,231	$ 2,988	$ 41	$ 45	$ 74
Sales to AEP Affiliates	—	(196)	—	196	—
Regulatory Assets (a)	(2,571)	(471)	(852)	(109)	(284)
Regulatory Liabilities (a)	(3,606)	(176)	(1,555)	120	(180)
Total Gain (Loss) on Risk Management Contracts	$ (4,946)	$ 2,145	$ (2,366)	$ 252	$ (390)

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2015

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 790	$ 3,591	$ (882)	$ 16	$ 19
Sales to AEP Affiliates	1,511	4,341	—	—	—
Other Operation Expense	(287)	(221)	(389)	(307)	(373)
Maintenance Expense	(503)	(221)	(396)	(248)	(265)
Purchased Electricity for Resale	1,571	347	30	—	—
Regulatory Assets (a)	2,136	(1,213)	—	615	(1,234)
Regulatory Liabilities (a)	31,797	4,121	(24,880)	5,076	14,446
Total Gain (Loss) on Risk Management Contracts	$ 37,015	$ 10,745	$ (26,517)	$ 5,152	$ 12,593

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2014

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 7,262	$ 10,467	$ 97	$ 172	$ 18
Sales to AEP Affiliates	—	(717)	—	717	—
Regulatory Assets (a)	(2,567)	(471)	(215)	(119)	(285)
Regulatory Liabilities (a)	42,444	26,934	39,311	(69)	119
Total Gain (Loss) on Risk Management Contracts	$ 47,139	$ 36,213	$ 39,193	$ 701	$ (148)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the condensed statements of income on an accrual basis.

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 condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the condensed statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed 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."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015, see Note 4 - Rate Matters. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated Vertically Integrated Utility and Generation & Marketing segment entities participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

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 Registrant Subsidiaries 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 condensed balance sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on the condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on the condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2015, the Registrant Subsidiaries did not designate power derivatives as cash flow hedges. During the three and nine months ended September 30, 2014, APCo and I&M designated power derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. The impact of cash flow hedge accounting for these derivative contracts was immaterial and was discontinued effective March 31, 2014.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Interest Expense on the condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2015 and 2014, the Registrant Subsidiaries did not designate interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2015 and 2014, the Registrant Subsidiaries did not designate any foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of September 30, 2015 and December 31, 2014 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Condensed Balance Sheets September 30, 2015

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ —	$ —	$ —	$ —	$ —	$ 3,805
I&M	—	—	—	—	—	(13,604)
OPCo	—	—	—	—	—	4,572
PSO	—	—	—	—	—	4,374
SWEPCo	—	—	—	—	—	(9,470)

	Expected to be Reclassified to Net Income During the Next Twelve Months		
Company	Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$ —	$ 734	0
I&M	—	(1,277)	0
OPCo	—	1,282	0
PSO	—	771	0
SWEPCo	—	(1,728)	0

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Condensed Balance Sheets December 31, 2014

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ —	$ —	$ —	$ —	$ —	$ 3,896
I&M	—	—	—	—	—	(14,406)
OPCo	—	—	—	—	—	5,602
PSO	—	—	—	—	—	4,943
SWEPCo	—	—	—	—	—	(11,036)

	Expected to be Reclassified to Net Income During the Next Twelve Months	
Company	Commodity	Interest Rate and Foreign Currency
	(in thousands)	
APCo	$ —	$ 275
I&M	—	(1,090)
OPCo	—	1,372
PSO	—	759
SWEPCo	—	(1,998)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed balance sheets.

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

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their 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. AEPSC, on behalf of the Registrant Subsidiaries, 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.

When AEPSC, on behalf of the Registrant Subsidiaries, uses standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds 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, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, the Registrant Subsidiaries are obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. The Registrant Subsidiaries have not experienced a downgrade below investment grade. The following tables represent the Registrant Subsidiaries' exposure if credit ratings were to decline below a specified rating threshold as of September 30, 2015 and December 31, 2014:

	September 30, 2015			
Company	Fair Value of Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post for Derivative Contracts as well as Non-Derivative Contracts Subject to the Same Master Netting Arrangement	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts
	(in thousands)			
APCo	$ —	$ —	$ 2,913	$ 97
I&M	—	—	1,976	66
OPCo	—	—	—	—
PSO	—	—	2,692	3,247
SWEPCo	—	—	3,328	58

	December 31, 2014			
Company	Fair Value of Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post for Derivative Contracts as well as Non-Derivative Contracts Subject to the Same Master Netting Arrangement	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts
	(in thousands)			
APCo	$ —	$ —	$ 6,339	$ 74
I&M	—	—	4,299	47
OPCo	—	—	—	—
PSO	—	—	693	4,111
SWEPCo	—	—	877	166

In addition, a majority of the Registrant Subsidiaries' non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, 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 this exposure has been reduced by cash collateral posted by the Registrant Subsidiaries and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of September 30, 2015 and December 31, 2014:

	September 30, 2015		
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 thousands)	
APCo	$ 5,310	$ —	$ 5,288
I&M	3,601	—	3,586
OPCo	—	—	—
PSO	—	—	—
SWEPCo	—	—	—

	December 31, 2014		
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 thousands)	
APCo	$ 9,043	$ —	$ 9,012
I&M	6,134	—	6,113
OPCo	—	—	—
PSO	—	—	—
SWEPCo	—	—	—

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System'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) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

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 the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

AEP utilizes its trustee's external pricing service in its estimate of 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, Restricted Cash for Securitized Funding and Cash and Cash Equivalents are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of September 30, 2015 and December 31, 2014 are summarized in the following table:

	September 30, 2015		December 31, 2014	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
APCo	$ 3,955,295	$ 4,460,140	$ 3,980,274	$ 4,711,210
I&M	2,060,651	2,241,930	2,027,397	2,255,124
OPCo	2,166,050	2,502,105	2,297,123	2,709,452
PSO	1,290,973	1,424,300	1,041,036	1,216,205
SWEPCo	2,283,966	2,446,716	2,140,437	2,402,639

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow 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 or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both fixed income and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and fixed income investments held in these trusts and generally intends to sell fixed income 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 trust assets are recorded by jurisdiction and may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments as of September 30, 2015 and December 31, 2014:

	September 30, 2015			December 31, 2014		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	$ 164,353	$ —	$ —	$ 19,966	$ —	$ —
Fixed Income Securities:						
United States Government	704,344	45,005	(2,291)	697,042	44,615	(5,016)
Corporate Debt	62,118	3,682	(1,043)	47,792	4,523	(1,018)
State and Local Government	50,018	996	(324)	208,553	1,206	(319)
Subtotal Fixed Income Securities	816,480	49,683	(3,658)	953,387	50,344	(6,353)
Equity Securities - Domestic	1,066,427	516,206	(80,280)	1,122,379	598,788	(79,142)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,047,260	$ 565,889	$ (83,938)	$ 2,095,732	$ 649,132	$ (85,495)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Proceeds from Investment Sales	$ 921,552	$ 263,738	$ 1,437,336	$ 746,272
Purchases of Investments	938,438	280,626	1,479,149	789,461
Gross Realized Gains on Investment Sales	15,030	7,617	33,840	24,835
Gross Realized Losses on Investment Sales	13,167	1,739	22,823	10,447

The adjusted cost of fixed income securities was $766 million and $903 million as of September 30, 2015 and December 31, 2014, respectively. The adjusted cost of equity securities was $551 million and $524 million as of September 30, 2015 and December 31, 2014, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2015 was as follows:

	Fair Value of Fixed Income Securities
	(in thousands)
Within 1 year	$ 166,336
1 year – 5 years	335,823
5 years – 10 years	140,129
After 10 years	174,192
Total	$ 816,480

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2015 and December 31, 2014. 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.

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Restricted Cash for Securitized Funding (a)	$ 7,436	$ —	$ —	$ 57	$ 7,493
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (b) (c)	185	12,785	23,743	(7,328)	29,385
Total Assets:	$ 7,621	$ 12,785	$ 23,743	$ (7,271)	$ 36,878
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (b) (c)	$ 198	$ 16,031	$ 662	$ (9,016)	$ 7,875

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Restricted Cash for Securitized Funding (a)	$ 15,599	$ —	$ —	$ 33	$ 15,632
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (b) (c)	206	20,197	17,654	(9,374)	28,683
Total Assets:	$ 15,805	$ 20,197	$ 17,654	$ (9,341)	$ 44,315
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (b) (c)	$ 227	$ 20,339	$ 1,912	$ (9,404)	$ 13,074

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (b) (c)	$ 126	$ 10,347	$ 7,795	$ (6,303)	$ 11,965
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	157,409	—	—	6,944	164,353
Fixed Income Securities:					
United States Government	—	704,344	—	—	704,344
Corporate Debt	—	62,118	—	—	62,118
State and Local Government	—	50,018	—	—	50,018
Subtotal Fixed Income Securities	—	816,480	—	—	816,480
Equity Securities - Domestic (e)	1,066,427	—	—	—	1,066,427
Total Spent Nuclear Fuel and Decommissioning Trusts	1,223,836	816,480	—	6,944	2,047,260
Total Assets	$ 1,223,962	$ 826,827	$ 7,795	$ 641	$ 2,059,225
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (b) (c)	$ 135	$ 10,945	$ 1,419	$ (6,636)	$ 5,863

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (b) (c)	$ 140	$ 15,893	$ 16,008	$ (6,396)	$ 25,645
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	9,418	—	—	10,548	19,966
Fixed Income Securities:					
United States Government	—	697,042	—	—	697,042
Corporate Debt	—	47,792	—	—	47,792
State and Local Government	—	208,553	—	—	208,553
Subtotal Fixed Income Securities	—	953,387	—	—	953,387
Equity Securities - Domestic (e)	1,122,379	—	—	—	1,122,379
Total Spent Nuclear Fuel and Decommissioning Trusts	1,131,797	953,387	—	10,548	2,095,732
Total Assets	$ 1,131,937	$ 969,280	$ 16,008	$ 4,152	$ 2,121,377
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (b) (c)	$ 154	$ 11,440	$ 1,304	$ (6,280)	$ 6,618

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Restricted Cash for Securitized Funding (a)	$ 16,195	$ —	$ —	$ 9	$ 16,204
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	—	20,719	2,546	23,265
Total Assets	$ 16,195	$ —	$ 20,719	$ 2,555	$ 39,469
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$ —	$ 639	$ 5,009	$ 2,046	$ 7,694

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Restricted Cash for Securitized Funding (a)	$ 408	$ —	$ —	$ 28,288	$ 28,696
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	—	52,343	1	52,344
Total Assets	$ 408	$ —	$ 52,343	$ 28,289	$ 81,040
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$ —	$ 1,116	$ 3,941	$ (101)	$ 4,956

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2015

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$ —	$ —	$ 1,166	$ (131)	$ 1,035
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$ —	$ 358	$ 131	$ (411)	$ 78

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$ —	$ —	$ 360	$ (360)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$ —	$ 595	$ 737	$ (414)	$ 918

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Cash and Cash Equivalents (a)	$ 11,688	$ —	$ —	$ 2,570	$ 14,258
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	—	1,442	(162)	1,280
Total Assets	$ 11,688	$ —	$ 1,442	$ 2,408	$ 15,538
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$ —	$ 2,378	$ 162	$ (481)	$ 2,059

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			*(in thousands)*		
Cash and Cash Equivalents (a)	$ 12,660	$ —	$ —	$ 1,696	$ 14,356
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	31	439	(439)	31
Total Assets	$ 12,660	$ 31	$ 439	$ 1,257	$ 14,387
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$ —	$ 684	$ 899	$ (501)	$ 1,082

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investment in money market funds.
(b) 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."
(c) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.
(d) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(e) Amounts represent publicly traded equity securities and equity-based mutual funds.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2015 and 2014.

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 for the Registrant Subsidiaries:

Three Months Ended September 30, 2015	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of June 30, 2015	$ 33,836	$ 11,844	$ 37,657	$ 1,699	$ 2,039
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	5,065	885	(28)	(280)	2,366
Purchases, Issuances and Settlements (d)	(13,965)	(3,604)	348	(176)	(2,912)
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	(1,855)	(2,749)	(22,267)	(208)	(213)
Balance as of September 30, 2015	$ 23,081	$ 6,376	$ 15,710	$ 1,035	$ 1,280

Three Months Ended September 30, 2014	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of June 30, 2014	$ 18,394	$ 12,923	$ 9,300	$ (3)	$ (3)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	(5,629)	(3,832)	(3,639)	2	2
Purchases, Issuances and Settlements (d)	(1,560)	(1,244)	(637)	—	—
Transfers into Level 3 (e) (f)	(6)	(4)	—	—	—
Transfers out of Level 3 (f) (g)	(30)	(20)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	4,843	4,319	2,865	335	409
Balance as of September 30, 2014	$ 16,012	$ 12,142	$ 7,889	$ 334	$ 408

Nine Months Ended September 30, 2015	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2014	$ 15,742	$ 14,704	$ 48,402	$ (377)	$ (460)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	1,757	(193)	1,182	(176)	9,187
Purchases, Issuances and Settlements (d)	(16,124)	(12,807)	(7,906)	553	(8,727)
Transfers out of Level 3 (f) (g)	1,167	792	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	20,539	3,880	(25,968)	1,035	1,280
Balance as of September 30, 2015	$ 23,081	$ 6,376	$ 15,710	$ 1,035	$ 1,280

Nine Months Ended September 30, 2014	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2013	$ 10,562	$ 7,164	$ 2,920	$ —	$ —
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	29,467	18,438	30,768	—	—
Purchases, Issuances and Settlements (d)	(32,213)	(20,301)	(33,688)	—	—
Transfers into Level 3 (e) (f)	(3,648)	(2,475)	—	—	—
Transfers out of Level 3 (f) (g)	(32)	(22)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	11,876	9,338	7,889	334	408
Balance as of September 30, 2014	$ 16,012	$ 12,142	$ 7,889	$ 334	$ 408

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on the condensed 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 the settlement of risk management commodity contracts for the reporting period.
(e) Represents existing assets or liabilities that were previously categorized as Level 2.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Represents existing assets or liabilities that were previously categorized as Level 3.
(h) Relates to the net gains (losses) of those contracts that are not reflected on the condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions for the Registrant Subsidiaries as of September 30, 2015 and December 31, 2014:

Significant Unobservable Inputs
September 30, 2015

APCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 8,724	$ 451	Discounted Cash Flow	Forward Market Price	$ 13.03	$ 48.17	$ 34.76
FTRs	15,019	211	Discounted Cash Flow	Forward Market Price	(5.95)	11.60	1.53
Total	$ 23,743	$ 662					

Significant Unobservable Inputs
December 31, 2014

APCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 5,801	$ 1,799	Discounted Cash Flow	Forward Market Price	$ 13.43	$ 123.02	$ 52.47
FTRs	11,853	113	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$ 17,654	$ 1,912					

Significant Unobservable Inputs
September 30, 2015

I&M

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 7,147	$ 295	Discounted Cash Flow	Forward Market Price	$ 13.03	$ 48.17	$ 34.76
FTRs	648	1,124	Discounted Cash Flow	Forward Market Price	(5.95)	11.60	1.53
Total	$ 7,795	$ 1,419					

Significant Unobservable Inputs
December 31, 2014

I&M

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 6,375	$ 1,219	Discounted Cash Flow	Forward Market Price	$ 13.43	$ 123.02	$ 52.47
FTRs	9,633	85	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$ 16,008	$ 1,304					

Significant Unobservable Inputs
September 30, 2015

OPCo

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 20,719	$ 5,009	Discounted Cash Flow	Forward Market Price	$ 35.71	$ 165.93	$ 85.99

Significant Unobservable Inputs
December 31, 2014

OPCo

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 45,101	$ 3,941	Discounted Cash Flow	Forward Market Price	$ 48.25	$ 159.92	$ 84.04
FTRs	7,242	—	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$ 52,343	$ 3,941					

Significant Unobservable Inputs
September 30, 2015

PSO

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
FTRs	$ 1,166	$ 131	Discounted Cash Flow	Forward Market Price	$ (5.95)	$ 11.60	$ 1.53

Significant Unobservable Inputs
December 31, 2014

PSO

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
FTRs	$ 360	$ 737	Discounted Cash Flow	Forward Market Price	$ (14.63)	$ 20.02	$ 1.01

Significant Unobservable Inputs
September 30, 2015

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
FTRs	$ 1,442	$ 162	Discounted Cash Flow	Forward Market Price	$ (5.95)	$ 11.60	$ 1.53

Significant Unobservable Inputs
December 31, 2014

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
FTRs	$ 439	$ 899	Discounted Cash Flow	Forward Market Price	$ (14.63)	$ 20.02	$ 1.01

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrant Subsidiaries as of September 30, 2015:

Sensitivity of Fair Value Measurements
September 30, 2015

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)

10. INCOME TAXES

AEP System Tax Allocation Agreement

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

The Registrant 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. 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 Registrant Subsidiaries 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 the Registrant Subsidiaries' net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and the Registrant 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 the Registrant Subsidiaries' net income. The Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2009.

State Tax Legislation

House Bill 32 was passed by the state of Texas in June 2015 permanently reducing the Texas income/franchise tax rate from 0.95% to 0.75% effective January 1, 2016, applicable to reports originally due on or after the effective date. The Texas income/franchise tax rate had been scheduled to return to 1% in 2016. The enacted provision did not materially impact the Registrant Subsidiaries' net income, cash flows or financial condition.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2015 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		**(in thousands)**	**(%)**	
APCo	Pollution Control Bonds	$ 86,000	1.90	2019
APCo	Senior Unsecured Notes	350,000	4.45	2045
APCo	Senior Unsecured Notes	300,000	3.40	2025
I&M	Notes Payable	111,300	Variable	2019
I&M	Other Long-term Debt	100,000	Variable	2018
PSO	Senior Unsecured Notes	125,000	3.17	2025
PSO	Senior Unsecured Notes	125,000	4.09	2045
SWEPCo	Pollution Control Bonds	53,500	1.60	2019
SWEPCo	Senior Unsecured Notes	400,000	3.90	2045

(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.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		**(in thousands)**	**(%)**	
APCo	Land Note	$ 28	13.718	2026
APCo	Notes Payable - Affiliated	86,000	3.125	2015
APCo	Securitization Bonds	22,524	2.008	2024
APCo	Senior Unsecured Notes	350,000	7.95	2020
APCo	Senior Unsecured Notes	300,000	3.40	2015
I&M	Notes Payable	18,600	Variable	2016
I&M	Notes Payable	20,601	Variable	2017
I&M	Notes Payable	26,512	Variable	2019
I&M	Notes Payable	16,265	Variable	2019
I&M	Notes Payable	1,273	Variable	2016
I&M	Notes Payable	882	2.12	2016
I&M	Other Long-term Debt	93,500	Variable	2015
I&M	Other Long-term Debt	838	6.00	2025
OPCo	Other Long-term Debt	58	1.149	2028
OPCo	Pollution Control Bonds	86,000	3.125	2015
OPCo	Securitization Bonds	45,426	0.958	2018
PSO	Other Long-term Debt	319	3.00	2027
SWEPCo	Notes Payable	3,250	4.58	2032
SWEPCo	Pollution Control Bonds	53,500	3.25	2015
SWEPCo	Senior Unsecured Notes	100,000	5.375	2015
SWEPCo	Senior Unsecured Notes	150,000	4.90	2015

As of September 30, 2015, trustees held on behalf of I&M and OPCo, $40 million and $345 million, respectively, of their reacquired Pollution Control Bonds.

Dividend Restrictions

The Registrant 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 Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant Subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their respective ownership of such plants, this reserve applies to APCo and I&M.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, APCo, I&M, PSO and SWEPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

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 a majority of AEP's 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, 2015 and December 31, 2014 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' condensed balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the nine months ended September 30, 2015 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, 2015	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 82,417	$ 694,785	$ 46,664	$ 97,657	$ (11,689)	$ 600,000
I&M	200,032	13,515	136,890	13,503	(137,496)	500,000
OPCo	—	367,472	—	256,020	279,129	400,000
PSO	165,947	152,498	113,117	74,225	116,345	300,000
SWEPCo	112,481	299,932	52,596	121,845	43,073	350,000

The activity in the above table does not include short-term lending activity of SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC, which is a participant in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2015 and December 31, 2014 are included in Advances to Affiliates on SWEPCo's condensed balance sheets. For the nine months ended September 30, 2015, Mutual Energy SWEPCo, LLC had the following activity in the Nonutility Money Pool:

Maximum Borrowings from the Nonutility Money Pool	Maximum Loans to the Nonutility Money Pool	Average Borrowings from the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2015
		(in thousands)		
$ —	$ 1,948	$ —	$ 1,945	$ 1,946

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, 2015	Nine Months Ended September 30, 2014
Maximum Interest Rate	0.59%	0.33%
Minimum Interest Rate	0.39%	0.24%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 30, 2015 and 2014 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	2015	2014	2015	2014
APCo	0.46%	0.26%	0.46%	0.28%
I&M	0.47%	0.27%	0.46%	0.30%
OPCo	—%	0.27%	0.47%	0.29%
PSO	0.49%	0.27%	0.46%	—%
SWEPCo	0.46%	0.28%	0.48%	0.27%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool for the nine months ended September 30, 2015 and 2014 are summarized for Mutual Energy SWEPCo, LLC in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
2015	—%	—%	0.59%	0.39%	—%	0.47%
2014	—%	—%	0.33%	—%	—%	0.28%

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Sale of Receivables – AEP Credit

Under a 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' condensed statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2017.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of September 30, 2015 and December 31, 2014 was as follows:

Company	September 30, 2015	December 31, 2014
	(in thousands)	
APCo	$ 125,153	$ 159,823
I&M	139,481	137,459
OPCo	354,276	365,834
PSO	146,039	112,905
SWEPCo	176,113	148,668

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in thousands)			
APCo	$ 1,952	$ 2,166	$ 5,979	$ 6,626
I&M	2,191	2,011	6,611	5,836
OPCo	8,545	7,213	23,228	21,358
PSO	1,709	1,745	4,455	4,417
SWEPCo	1,997	1,890	5,344	5,035

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

Company	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in thousands)			
APCo	$ 355,275	$ 354,406	$ 1,115,492	$ 1,137,564
I&M	401,518	372,422	1,192,137	1,132,603
OPCo	670,677	668,112	1,949,042	1,980,764
PSO	411,523	398,567	1,025,909	1,014,320
SWEPCo	468,027	466,828	1,222,294	1,278,325

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding. APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding. In addition, the Registrant Subsidiaries have not provided material financial or other support to any of these entities that was not previously contractually required. SWEPCo holds a significant variable interest in DHLC. Each of the Registrant Subsidiaries hold a significant variable interest in AEPSC. I&M holds a significant variable interest in AEGCo.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended September 30, 2015 and 2014 were $41 million and $41 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $124 million and $121 million, respectively. See the table below for the classification of Sabine's assets and liabilities on SWEPCo's condensed balance sheets.

The balances below represent the assets and liabilities of Sabine that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
September 30, 2015 and December 31, 2014
(in thousands)

	Sabine	
ASSETS	**2015**	**2014**
Current Assets	$ 61,025	$ 67,981
Net Property, Plant and Equipment	143,815	145,491
Other Noncurrent Assets	60,160	51,578
Total Assets	$ 265,000	$ 265,050
LIABILITIES AND EQUITY		
Current Liabilities	$ 40,311	$ 36,286
Noncurrent Liabilities	224,371	228,349
Equity	318	415
Total Liabilities and Equity	$ 265,000	$ 265,050

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended September 30, 2015 and 2014 were $29 million and $28 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $86 million and $84 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the table below for the classification of DCC Fuel's assets and liabilities on I&M's condensed balance sheets.

The balances below represent the assets and liabilities of DCC Fuel that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2015 and December 31, 2014
(in thousands)

	DCC Fuel	
ASSETS	**2015**	**2014**
Current Assets	$ 104,273	$ 97,361
Net Property, Plant and Equipment	193,447	158,121
Other Noncurrent Assets	99,811	79,705
Total Assets	$ 397,531	$ 335,187
LIABILITIES AND EQUITY		
Current Liabilities	$ 98,173	$ 86,026
Noncurrent Liabilities	299,358	249,161
Total Liabilities and Equity	$ 397,531	$ 335,187

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $187 million and $232 million as of September 30, 2015 and December 31, 2014, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the condensed balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $92 million and $110 million as of September 30, 2015 and December 31, 2014, respectively, which are presented separately on the face of the condensed balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's condensed balance sheets.

The balances below represent the assets and liabilities of Ohio Phase-in-Recovery Funding that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

OHIO POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2015 and December 31, 2014
(in thousands)

	Ohio Phase-In Recovery Funding	
ASSETS	**2015**	**2014**
Current Assets	$ 20,236	$ 32,676
Other Noncurrent Assets (a)	175,189	209,922
Total Assets	$ 195,425	$ 242,598
LIABILITIES AND EQUITY		
Current Liabilities	$ 46,592	$ 47,099
Noncurrent Liabilities	147,496	194,162
Equity	1,337	1,337
Total Liabilities and Equity	$ 195,425	$ 242,598

(a) Includes an intercompany item eliminated in consolidation as of September 30, 2015 and December 31, 2014 of $81 million and $97 million, respectively.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $345 million and $368 million as of September 30, 2015 and December 31, 2014, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the condensed balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $333 million and $350 million as of September 30, 2015 and December 31, 2014, respectively, which are presented separately on the face of the condensed balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's condensed balance sheets.

The balances below represent the assets and liabilities of Appalachian Consumer Rate Relief Funding that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2015 and December 31, 2014
(in thousands)

	Appalachian Consumer Rate Relief Funding	
ASSETS	**2015**	**2014**
Current Assets	$ 10,914	$ 18,099
Other Noncurrent Assets (a)	341,127	358,264
Total Assets	$ 352,041	$ 376,363
LIABILITIES AND EQUITY		
Current Liabilities	$ 24,617	$ 26,809
Noncurrent Liabilities	325,534	347,652
Equity	1,890	1,902
Total Liabilities and Equity	$ 352,041	$ 376,363

(a) Includes an intercompany item eliminated in consolidation as of September 30, 2015 and December 31, 2014 of $4 million and $4 million, respectively.

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the three months ended September 30, 2015 and 2014 were $30 million and $24 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $59 million and $31 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's condensed balance sheets.

SWEPCo's investment in DHLC was:

	September 30, 2015		December 31, 2014	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
Capital Contribution from SWEPCo	$ 7,643	$ 7,643	$ 7,643	$ 7,643
Retained Earnings	5,950	5,950	3,819	3,819
SWEPCo's Guarantee of Debt	—	95,180 (a)	—	104,334 (a)
Total Investment in DHLC	$ 13,593	$ 108,773	$ 11,462	$ 115,796

(a) Includes affiliate advances due to Parent related to participation in the Utility Money Pool of $40 million and $56 million in 2015 and 2014, respectively.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

Company	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(in thousands)			
APCo	$ 63,687	$ 50,143	$ 164,657	$ 154,239
I&M	37,506	30,613	102,141	92,686
OPCo	48,471	41,212	128,608	120,696
PSO	29,851	24,317	77,817	71,646
SWEPCo	39,150	32,787	102,564	98,528

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	September 30, 2015		December 31, 2014	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
APCo	$ 23,783	$ 23,783	$ 30,692	$ 30,692
I&M	13,676	13,676	22,480	22,480
OPCo	18,770	18,770	24,695	24,695
PSO	10,713	10,713	15,338	15,338
SWEPCo	14,295	14,295	20,772	20,772

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1, leases a 50% interest in Rockport Plant, Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo has a Unit Power Agreement associated with the Lawrenceburg Generating Station which was assigned by OPCo and AGR effective January 1, 2014. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligation of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the three months ended September 30, 2015 and 2014 were $67 million and $67 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $182 million and $202 million, respectively. The carrying amount of I&M's liabilities associated with AEGCo as of September 30, 2015 and December 31, 2014 was $17 million and $20 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13 in the 2014 Annual Report.

13. PROPERTY, PLANT AND EQUIPMENT

Asset Retirement Obligations (ARO)

The Registrant Subsidiaries record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant and coal mining facilities, as well as asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

As of September 30, 2015 and December 31, 2014, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.31 billion and $1.27 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's condensed balance sheets. As of September 30, 2015 and December 31, 2014, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.74 billion and $1.79 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's condensed balance sheets.

The Registrant Subsidiaries recorded an increase in asset retirement obligations in the second quarter of 2015, partially related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment.

The following is a reconciliation of the aggregate carrying amounts of ARO by Registrant Subsidiary:

Company	ARO as of December 31, 2014	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of September 30, 2015
				(in thousands)		
APCo (a)(d)	$ 148,377	$ 6,239	$ —	$ (23,471)	$ 16,977	$ 148,122
I&M (a)(b)(d)	1,342,549	47,918	—	(3,977)	5,638	1,392,128
OPCo (d)(e)	1,361	62	—	(8)	—	1,415
PSO (a)(d)	38,020	1,923	5,336	(125)	1,916	47,070
SWEPCo (a)(c)(d)	94,394	4,299	12,191	(3,358)	6,349	113,875

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.31 billion and $1.27 billion as of September 30, 2015 and December 31, 2014.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) Not impacted by the CCR rule.

14. DISPOSITION PLANT SEVERANCE

Management retired several generation plants or units of plants during 2015. These plant closures resulted in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The Registrant Subsidiaries' disposition plant severance activity for the nine months ended September 30, 2015 is described in the following table:

Company	Balance as of December 31, 2014	Expense Allocation from AEPSC	Incurred by Registrant Subsidiaries	Settled	Adjustments	Remaining Balance as of September 30, 2015
			(in thousands)			
APCo	$ 9,304	$ (6)	$ 849	$ (6,385) (a)	$ (119)	$ 3,643
I&M	8,023	(2)	351	(5,110)	—	3,262
PSO	134	(3)	415	(121)	—	425
SWEPCo	84	(4)	—	(79)	—	1

(a) Settled includes amounts received from affiliates for expenses related to joint plant.

The Registrant Subsidiaries recorded charges to Other Operation expense in 2014 primarily related to employees at the disposition plants. The total amount incurred in 2014 by Registrant Subsidiary was as follows:

Company	Total Cost Incurred
	(in thousands)
APCo	$ 7,112
I&M	8,185
OPCo	80
PSO	288
SWEPCo	289

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. The Registrant Subsidiaries incurred additional charges during the second quarter of 2015 as severance plans were finalized after the plants were retired. Management does not expect additional severance costs to be incurred related to this initiative.

COMBINED MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (a) Management's Narrative Discussion and Analysis of Results of Operations, (b) financial statements, (c) footnotes and (d) the schedules of each individual registrant. The Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries section of the 2014 Annual Report should also be read in conjunction with this report.

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the third quarter of 2015 increased by 0.9% from the third quarter of 2014. Third quarter 2015 industrial sales increased 0.7% compared to the third quarter of 2014 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized commercial and residential sales increased 1.3% and 0.8% in the third quarter of 2015, respectively, from the third quarter of 2014.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2015 increased 0.1% compared to the nine months ended September 30, 2014. Industrial sales volumes increased 0.8% compared to 2014, while weather-normalized commercial sales increased by 1.0%. Weather-normalized residential sales decreased 1.1% in comparison to the first nine months of 2014.

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. The Registrant Subsidiaries will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, rules governing the beneficial use and disposal of coal combustion products, proposed and final clean water rules and renewal permits for certain water discharges that are currently under appeal.

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

See a complete discussion of these matters in the "Environmental Issues" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2014 Annual Report. Management will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If the costs of environmental compliance are not recovered, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2015, the AEP System had a total generating capacity of approximately 32,100 MWs, of which approximately 18,200 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these requirements are listed below:

	Through 2020 Estimated Environmental Investment	
Company	**Low**	**High**
	(in millions)	
APCo	$ 310	$ 360
I&M	370	430
PSO	270	310
SWEPCo	880	950
Total	$ 1,830	$ 2,050

For APCo, the projected environmental investment above includes the conversion of 470 MWs of coal generation to natural gas capacity.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates for each Registrant Subsidiary will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

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

Company	Plant Name and Unit	Generating Capacity
		(in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
Total		2,565

As of September 30, 2015, the book value of the regulated plants in the table above has been approved for recovery, except for $147 million which is pending regulatory approval.

Subject to the factors listed above and based upon continuing evaluation, management intends to retire the following units of plants during 2016:

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

As of September 30, 2015, the net book value of the PSO and SWEPCo units listed above before cost of removal, including related materials and supplies inventory and CWIP balances, was $177 million. Volatility in fuel prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For Northeastern Station, Unit 4 and Welsh Plant, Unit 2, management is seeking regulatory recovery of remaining net book values.

Management is in the process of obtaining permits following the Virginia SCC and WVPSC's approval for the conversion of APCo's 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In September 2015, management retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the coal-related assets retired in September 2015, $14 million is pending regulatory approval. Management expects to begin operations as a natural gas unit in the first quarter of 2016 for Clinch River Plant, Unit 1 and the second quarter of 2016 for Clinch River Plant, Unit 2. As of September 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of Clinch River Plant, Units 1 and 2 was $148 million.

To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

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

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" section below.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) will address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls currently under construction. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In July 2015, management submitted comments to the proposed Arkansas FIP and participate in comments filed by industry associations of which the AEP System is a member. Management supports compliance with CSAPR programs as satisfaction of the BART requirements.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. This rule was overturned by the U.S. Supreme Court. The Federal EPA proposed to include CO_2 emissions in standards that apply to new and existing electric utility units. See "Climate Change, CO_2 Regulation and Energy Policy" section below.

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

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

Cross-State Air Pollution Rule (CSAPR)

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

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

District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place. The Federal EPA is reviewing the decision and will take further action once their review is complete. Separate appeals of the Error Corrections Rule and the further revisions were filed but no briefing schedules have been established.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance was required within three years. The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and the revised rule provides alternative work practice standards for operators during start-up and shut down periods. Management has obtained a one-year administrative extension at several units to facilitate the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. Management remains concerned about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards (MATS) schedule and other environmental requirements.

Petitions for administrative reconsideration and judicial review of the final rule were filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. A final rule on reconsideration was issued in 2014 and a proposed rule containing technical corrections was issued in early 2015. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanded the MATS rule for further proceedings consistent with its decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The case has been remanded to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings consistent with the U.S. Supreme Court's decision. Management will continue to evaluate the impact of this decision and until further action by the U.S. Court of Appeals for the District of Columbia Circuit, the rule remains in place.

Climate Change, CO_2 Regulation and Energy Policy

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where the Registrant Subsidiaries have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. The Registrant Subsidiaries are taking steps to comply with these requirements, including increasing wind power purchases and broadening the AEP System's portfolio of energy efficiency programs.

In the absence of comprehensive federal climate change or energy policy legislation, President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units under the CAA. The new proposal was issued in September 2013 and requires new large natural gas units to meet a limit of 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet a limit of 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet a limit of 1,100 pounds of CO_2 per MWh, with the option to meet a 1,000 pound per MWh limit if they choose to average emissions over multiple years.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs before June 2014, to finalize those standards by June 2015 and to require states to submit plans implementing the guidelines no later than June 2016.

In August 2015, the Federal EPA announced the final standards for new, modified and reconstructed fossil fired steam generating units and combustion turbines, guidelines for the development of state plans to regulate CO_2 emissions from existing sources and proposed two options for a federal plan. The rules will become effective 60 days following publication. The final standard for new combustion turbines is 1,000 pounds of CO_2 per MWh and the final standard for new fossil steam units is 1,400 pounds of CO_2 per MWh. Reconstructed turbines are subject to the same standard as new units and no standard for modified combustion turbines was issued. Reconstructed fossil steam units are subject to a standard of 1,800 pounds of CO_2 per MWh for larger units and 2,000 pounds of CO_2 per MWh for smaller units. Modified fossil steam units will be subject to a site specific standard no lower than the standards that would be applied if the units were reconstructed.

The final emissions guidelines for existing sources are based on a series of declining performance standards that are implemented beginning in 2022 through 2029. Affected units must achieve a standard of 771 pounds of CO_2 per MWh for existing natural gas combined cycle units and 1,305 pounds of CO_2 per MWh for existing fossil steam units by 2030. The Federal EPA also developed a set of rate-based and mass-based state goals and has proposed "model" rules that can be adopted by the states that would allow sources within "trading ready" state programs to trade, bank or sell allowances or credits issued by the states or Federal EPA. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. States are required to submit final plans or an extension request by September 2016 to the Federal EPA. States receiving an extension request must submit final plans by September 2018. Management is reviewing the pre-publication version of the final rule and evaluating the rule's impacts as well as the anticipated actions by states where assets are located. The final rule was already challenged in the courts and management expects additional lawsuits once the rule is published in the Federal Register.

In 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology (BACT) analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA removed those provisions of the final rule from the Code of Federal Regulations that were inconsistent with the U.S. Supreme Court's decision but continues to apply a 75,000 ton per year threshold to trigger the need for a BACT analysis. Petitions were filed with the U.S. Court of Appeals for the District of Columbia Circuit seeking to amend the judgment in the case to require Federal EPA to establish a reasonable minimum level. Those petitions were denied.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force the Registrant Subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets.

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

In the final rule, the Federal EPA elected to regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. On the effective date, the rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements. The rule does not apply to inactive CCR landfills and inactive surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice and internet posting requirements. Because the Registrant Subsidiaries currently use surface impoundments and landfills to manage CCR materials at the generating facilities, they will incur significant costs to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented.

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

The final rule was published in the Federal Register in April 2015 and becomes effective six months after publication. The final rule provides for a staggered compliance schedule for the implementation of the rule's many requirements. Management recorded a $45 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Given the schedule for implementation, management will continue to evaluate the rule's impact on operations.

Clean Water Act (CWA) Regulations

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

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A pre-publication copy of the final rule was announced and made available in September 2015. In addition to other requirements, in the final rule the Federal EPA establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. Compliance with the final rule is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. Management will continue to review the final rule in detail to evaluate whether the plants are currently meeting the proposed limitations, what technologies have been incorporated into the long-range plans and what additional costs might be incurred.

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

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During the First Quarter of 2015

The FASB issued ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. Management adopted ASU 2014-08 effective January 1, 2015. There were no events requiring application of the new accounting guidance.

Pronouncements Effective in the Future

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

The FASB issued ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. Management plans to adopt ASU 2015-01 effective January 1, 2016.

The FASB issued ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs" to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. The Registrant Subsidiaries include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Form 10-K.

The FASB issued ASU 2015-05 "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement" providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management 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 2015-05 effective January 1, 2016.

The FASB issued ASU 2015-11 "Simplifying the Measurement of Inventory" to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management 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 2015-11 effective January 1, 2017.

The FASB issued ASU 2015-13 "Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets" clarifying whether a contract for the purchase or sale of electricity on a forward basis should be eligible to meet the physical delivery criterion of the normal purchases and normal sales scope exception when either the delivery location is within a nodal energy market or the contract necessitates transmission through a nodal energy market and one of the contracting parties incurs charges (or credits) for the transmission of electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. Under the new standard, the use of locational marginal pricing by an independent system operator does not cause a contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. As a result, an entity may elect to designate that contract as a normal purchase or normal sale. The new accounting guidance is effective upon issuance and applied prospectively. Management has analyzed the impact of this new standard and determined that it will have no impact on the accounting of the Registrant Subsidiaries' contracts. Additionally, adoption has no impact on net income. Management adopted ASU 2015-13 upon its issuance date.

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 the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including financial instruments, leases, insurance, hedge accounting, consolidation policy and balance sheet classification of deferred taxes. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

CONTROLS AND PROCEDURES

During the third quarter of 2015, management, including the principal executive officer and principal financial officer of each of AEP, APCo, I&M, OPCo, PSO and SWEPCo (collectively, 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, 2015, 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. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

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 2015 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 Annual Report on Form 10-K for the year ended December 31, 2014 includes a detailed discussion of risk factors. As of September 30, 2015, there have been no material changes to the risk factors previously disclosed in the 2014 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

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, and AGR and KPCo, through their use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act and its related regulations require 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 and Conner Run under the Mine Act for the quarter ended September 30, 2015.

Item 5. Other Information

None

Item 6. Exhibits

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

95 – Mine Safety Disclosures

101.INS – XBRL Instance Document
101.SCH – XBRL Taxonomy Extension Schema
101.CAL – XBRL Taxonomy Extension Calculation Linkbase
101.DEF – XBRL Taxonomy Extension Definition Linkbase
101.LAB – XBRL Taxonomy Extension Label Linkbase
101.PRE – XBRL Taxonomy Extension Presentation Linkbase

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

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 22, 2015