PINNACLE WEST CAPITAL CORP
Form 10-Q
November 03, 2017

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

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2017

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number	Exact Name of Each Registrant as specified in its charter; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-8962	PINNACLE WEST CAPITAL CORPORATION (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	ARIZONA PUBLIC SERVICE COMPANY (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0011170

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PINNACLE WEST CAPITAL CORPORATION	Yes	No
ARIZONA PUBLIC SERVICE COMPANY	Yes	No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PINNACLE WEST CAPITAL CORPORATION	Yes	No
ARIZONA PUBLIC SERVICE COMPANY	Yes	No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

PINNACLE WEST CAPITAL CORPORATION

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

Emerging growth company

ARIZONA PUBLIC SERVICE COMPANY

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

Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PINNACLE WEST CAPITAL CORPORATION	Yes	No
ARIZONA PUBLIC SERVICE COMPANY	Yes	No

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date.

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of October 27, 2017: 111,729,775
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of October 27, 2017: 71,264,947

Arizona Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

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This combined Form 10-Q is separately provided by Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS"). Any use of the words "Company," "we," and "our" refer to Pinnacle West. Each registrant is providing on its own behalf all of the information contained in this Form 10-Q that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is providing any information that does not relate to such registrant, and therefore makes no representation as to any such information. The information required with respect to each company is set forth within the applicable items. Item 1 of this report includes Condensed Consolidated Financial Statements of Pinnacle West and Condensed Consolidated Financial Statements of APS. Item 1 also includes Combined Notes to Condensed Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume," "project" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Part I, Item 1A of the Pinnacle West/APS Annual Report on Form 10-K for the fiscal year ended December 31, 2016 ("2016 Form 10-K"), Part II, Item 1A of the Pinnacle West/APS Quarterly Report on Form 10-Q for the quarter ended June 30, 2017 ("2017 2nd Quarter 10-Q"), Part II, Item 1A of this report and in Part I, Item 2 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this report, these factors include, but are not limited to:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, seasonality, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation, ballot initiatives and regulation, including those relating to environmental requirements, regulatory policy, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental, economic and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and Arizona Corporation Commission ("ACC") orders.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of our 2016 Form 10-K, Part II, Item 1A of our 2017 2nd Quarter 10-Q, and in Part II, Item 1A of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(dollars and shares in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$1,183,322	$1,166,922	$2,805,637	$2,759,483
OPERATING EXPENSES				
Fuel and purchased power	310,469	336,120	777,475	832,253
Operations and maintenance	224,305	217,568	658,294	703,042
Depreciation and amortization	133,912	120,428	387,278	362,977
Taxes other than income taxes	45,169	41,284	133,294	125,902
Other expenses	3,385	264	5,479	2,141
Total	717,240	715,664	1,961,820	2,026,315
OPERATING INCOME	466,082	451,258	843,817	733,168
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	12,728	10,194	32,666	31,079
Other income (Note 8)	1,091	71	2,055	385
Other expense (Note 8)	(4,993)	(5,205)	(12,495)	(12,085)
Total	8,826	5,060	22,226	19,379
INTEREST EXPENSE				
Interest charges	55,644	51,293	162,477	154,886
Allowance for borrowed funds used during construction	(6,000)	(4,321)	(15,378)	(14,849)
Total	49,644	46,972	147,099	140,037
INCOME BEFORE INCOME TAXES	425,264	409,346	718,944	612,510
INCOME TAXES	144,319	141,446	237,497	209,102
NET INCOME	280,945	267,900	481,447	403,408
Less: Net income attributable to noncontrolling interests (Note 5)	4,873	4,873	14,620	14,620
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$276,072	$263,027	$466,827	$388,788
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,835	111,416	111,787	111,363
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,401	112,100	112,314	111,987
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING				
Net income attributable to common shareholders — basic	$2.47	$2.36	$4.18	$3.49
Net income attributable to common shareholders — diluted	$2.46	$2.35	$4.16	$3.47
DIVIDENDS DECLARED PER SHARE	$—	$—	$1.31	$1.25

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
NET INCOME	$280,945	$267,900	$481,447	$403,408
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax (benefit) expense of $5, ($18), $684 and $608 for the respective periods	9	(29)	(754)	(595)
Reclassification of net realized loss, net of tax benefit of $438, $500, $430 and $691 for the respective periods	710	798	2,480	2,564
Pension and other postretirement benefits activity, net of tax expense of $487, $504, $369 and $709 for the respective periods	790	804	(21)	633
Total other comprehensive income	1,509	1,573	1,705	2,602
COMPREHENSIVE INCOME	282,454	269,473	483,152	406,010
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873	14,620	14,620
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$277,581	$264,600	$468,532	$391,390

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$10,674	$8,881
Customer and other receivables	425,558	250,491
Accrued unbilled revenues	151,976	107,949
Allowance for doubtful accounts	(3,051)	(3,037)
Materials and supplies (at average cost)	257,455	253,979
Fossil fuel (at average cost)	27,013	28,608
Income tax receivable	—	3,751
Assets from risk management activities (Note 6)	358	19,694
Deferred fuel and purchased power regulatory asset (Note 3)	73,966	12,465
Other regulatory assets (Note 3)	184,351	94,410
Other current assets	45,905	45,028
Total current assets	1,174,205	822,219
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 6)	1,692	1
Nuclear decommissioning trust (Note 11)	841,980	779,586
Other assets	88,818	69,063
Total investments and other assets	932,490	848,650
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	17,310,294	17,341,888
Accumulated depreciation and amortization	(6,037,467)	(5,970,100)
Net	11,272,827	11,371,788
Construction work in progress	1,379,501	1,019,947
Palo Verde sale leaseback, net of accumulated depreciation (Note 5)	110,613	113,515
Intangible assets, net of accumulated amortization	256,198	90,022
Nuclear fuel, net of accumulated amortization	135,460	119,004
Total property, plant and equipment	13,154,599	12,714,276
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,381,179	1,313,428
Assets for other postretirement benefits (Note 4)	193,747	166,206
Other	141,647	139,474
Total deferred debits	1,716,573	1,619,108
TOTAL ASSETS	$16,977,867	$16,004,253

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	September 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$236,746	$264,631
Accrued taxes	228,791	138,964
Accrued interest	49,218	52,835
Common dividends payable	—	72,926
Short-term borrowings (Note 2)	131,400	177,200
Current maturities of long-term debt (Note 2)	207,000	125,000
Customer deposits	69,690	82,520
Liabilities from risk management activities (Note 6)	50,469	25,836
Liabilities for asset retirements (Note 14)	1,559	9,135
Regulatory liabilities (Note 3)	120,671	99,899
Other current liabilities	207,599	244,000
Total current liabilities	1,303,143	1,292,946
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 2)	4,491,048	4,021,785
DEFERRED CREDITS AND OTHER		
Deferred income taxes	3,182,400	2,945,232
Regulatory liabilities (Note 3)	891,715	948,916
Liabilities for asset retirements (Note 14)	669,297	615,340
Liabilities for pension benefits (Note 4)	409,871	509,310
Liabilities from risk management activities (Note 6)	35,775	47,238
Customer advances	101,210	88,672
Coal mine reclamation	238,634	221,910
Deferred investment tax credit	205,870	210,162
Unrecognized tax benefits	12,943	10,046
Other	158,354	156,784
Total deferred credits and other	5,906,069	5,753,610
COMMITMENTS AND CONTINGENCIES (SEE NOTE 7)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,666,876 and 111,392,053 issued at respective dates	2,608,825	2,596,030
Treasury stock at cost; 9,864 and 55,317 shares at respective dates	(833)	(4,133)
Total common stock	2,607,992	2,591,897
Retained earnings	2,576,193	2,255,547
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(39,091)	(39,070)
Derivative instruments	(3,026)	(4,752)
Total accumulated other comprehensive loss	(42,117)	(43,822)
Total shareholders' equity	5,142,068	4,803,622
Noncontrolling interests (Note 5)	135,539	132,290
Total equity	5,277,607	4,935,912

TOTAL LIABILITIES AND EQUITY	$16,977,867	$16,004,253

The accompanying notes are an integral part of the financial statements.

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PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
(dollars in thousands)

	Nine Months Ended September 30, 2017		2016	
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 481,447		$ 403,408	
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization including nuclear fuel	445,707		422,851	
Deferred fuel and purchased power	(43,348	)	(46,185	)
Deferred fuel and purchased power amortization	(18,153	)	28,366	
Allowance for equity funds used during construction	(32,666	)	(31,079	)
Deferred income taxes	211,249		194,915	
Deferred investment tax credit	(4,293	)	(6,342	)
Change in derivative instruments fair value	(254	)	(278	)
Stock compensation	16,553		27,588	
Changes in current assets and liabilities:				
Customer and other receivables	(206,920	)	(77,908	)
Accrued unbilled revenues	(44,027	)	(54,291	)
Materials, supplies and fossil fuel	(1,881	)	(4,438	)
Income tax receivable	3,751		589	
Other current assets	(22,043	)	(11,665	)
Accounts payable	(24,258	)	(57,237	)
Accrued taxes	89,827		80,925	
Other current liabilities	3,936		(12,383	)
Change in margin and collateral accounts — assets	(1,826	)	517	
Change in margin and collateral accounts —	(1,625	)	18,085	

liabilities				
Change in unrecognized tax benefits	5,891		1,628	
Change in other long-term assets	(59,963	)	(59,589	)
Change in other long-term liabilities	(25,180	)	(52,427	)
Net cash flow provided by operating activities	771,924		765,050	
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	(1,027,753	)	(1,014,910	)
Contributions in aid of construction	24,924		39,355	
Allowance for borrowed funds used during construction	(15,378	)	(14,848	)
Proceeds from nuclear decommissioning trust sales	351,860		447,419	
Investment in nuclear decommissioning trust	(353,001	)	(449,129	)
Other	(20,291	)	(18,353	)
Net cash flow used for investing activities	(1,039,639	)	(1,010,466	)
CASH FLOWS FROM FINANCING ACTIVITIES				
Issuance of long-term debt	549,478		693,151	
Repayment of long-term debt	—		(353,560	)
Short-term borrowing and payments — net	(68,800	)	83,300	
Short-term borrowings under revolving credit facility	23,000		34,000	
Dividends paid on common stock	(213,927	)	(203,115	)
Common stock equity issuance - net of purchases	(8,870	)	11,790	
Distributions to noncontrolling interests	(11,372	)	(11,372	)
Other	(1	)	1	
Net cash flow provided by financing activities	269,508		254,195	
NET INCREASE IN CASH AND CASH	1,793		8,779	

EQUIVALENTS				
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	8,881		39,488	
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$	10,674	$	48,267

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(unaudited)
(dollars in thousands)

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, January 1, 2016	111,095,402	$2,541,668	(115,030)	$(5,806)	$2,092,803	$ (44,748)	$ 135,540	$4,719,457
Net income		—		—	388,788	—	14,620	403,408
Other comprehensive income		—		—	—	2,602	—	2,602
Dividends on common stock		—		—	(138,947)	—	—	(138,947)
Issuance of common stock	124,968	11,311		—	—	—	—	11,311
Purchase of treasury stock (a)		—	(71,962)	(4,880)	—	—	—	(4,880)
Reissuance of treasury stock for stock-based compensation and other		—	185,092	10,556	(1)	—	—	10,555
Capital activities by noncontrolling interests		—		—	—	—	(11,371)	(11,371)
Balance, September 30, 2016	111,220,370	$2,552,979	(1,900)	$(130)	$2,342,643	$ (42,146)	$ 138,789	$4,992,135
Balance, January 1, 2017	111,392,053	$2,596,030	(55,317)	$(4,133)	$2,255,547	$ (43,822)	$ 132,290	$4,935,912
Net income		—		—	466,827	—	14,620	481,447
Other comprehensive income		—		—	—	1,705	—	1,705
Dividends on common stock		—		—	(146,204)	—	—	(146,204)
Issuance of common stock	274,823	12,795		—	—	—	—	12,795
Purchase of treasury stock (a)		—	(162,312)	(12,964)	—	—	—	(12,964)
Reissuance of treasury stock for stock-based		—	207,765	16,264	23	—	1	16,288

compensation and other								
Capital activities by noncontrolling interests		—		—	—	—	(11,372)	(11,372)
Balance, September 30, 2017	111,666,876	$2,608,825	(9,864)	$(833)	$2,576,193	$(42,117)	$135,539	$5,277,607

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
ELECTRIC OPERATING REVENUES	$1,178,106	$1,166,359	$2,797,590	$2,752,748
OPERATING EXPENSES				
Fuel and purchased power	309,045	339,510	786,041	835,643
Operations and maintenance	215,264	209,366	635,769	681,789
Depreciation and amortization	133,486	120,013	386,010	362,492
Income taxes	153,425	148,945	257,182	225,239
Taxes other than income taxes	44,833	40,924	132,281	125,370
Total	856,053	858,758	2,197,283	2,230,533
OPERATING INCOME	322,053	307,601	600,307	522,215
OTHER INCOME (DEDUCTIONS)				
Income taxes	6,892	5,753	13,474	9,289
Allowance for equity funds used during construction	12,728	10,194	32,666	31,079
Other income (Note 8)	1,478	567	3,682	6,924
Other expense (Note 8)	(6,262)	(3,776)	(16,290)	(12,956)
Total	14,836	12,738	33,532	34,336
INTEREST EXPENSE				
Interest on long-term debt	50,429	46,970	147,909	142,692
Interest on short-term borrowings	2,140	2,401	6,599	6,408
Debt discount, premium and expense	1,191	1,196	3,566	3,529
Allowance for borrowed funds used during construction	(6,000)	(4,321)	(15,378)	(14,359)
Total	47,760	46,246	142,696	138,270
NET INCOME	289,129	274,093	491,143	418,281
Less: Net income attributable to noncontrolling interests (Note 5)	4,873	4,873	14,620	14,620
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$284,256	$269,220	$476,523	$403,661

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
NET INCOME	$289,129	$274,093	$491,143	$418,281
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax (benefit) expense of $5, ($18), $684 and $608 for the respective periods	9	(29)	(754)	(595)
Reclassification of net realized loss, net of tax benefit of $438, $500, $430 and $691 for the respective periods	710	798	2,480	2,564
Pension and other postretirement benefits activity, net of tax expense of $480, $501, $262 and $657 for the respective periods	777	799	81	768
Total other comprehensive income	1,496	1,568	1,807	2,737
COMPREHENSIVE INCOME	290,625	275,661	492,950	421,018
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873	14,620	14,620
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$285,752	$270,788	$478,330	$406,398

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	September 30, 2017	December 31, 2016
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 17,195,555	$ 17,228,787
Accumulated depreciation and amortization	(5,951,233)	(5,881,941)
Net	11,244,322	11,346,846
Construction work in progress	1,335,398	989,497
Palo Verde sale leaseback, net of accumulated depreciation (Note 5)	110,613	113,515
Intangible assets, net of accumulated amortization	256,037	89,868
Nuclear fuel, net of accumulated amortization	135,460	119,004
Total property, plant and equipment	13,081,830	12,658,730
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 11)	841,980	779,586
Assets from risk management activities (Note 6)	1,692	1
Other assets	66,418	48,320
Total investments and other assets	910,090	827,907
CURRENT ASSETS		
Cash and cash equivalents	10,633	8,840
Customer and other receivables	417,229	262,611
Accrued unbilled revenues	151,976	107,949
Allowance for doubtful accounts	(3,051)	(3,037)
Materials and supplies (at average cost)	256,127	252,777
Fossil fuel (at average cost)	27,013	28,608
Income tax receivable	—	11,174
Assets from risk management activities (Note 6)	358	19,694
Deferred fuel and purchased power regulatory asset (Note 3)	73,966	12,465
Other regulatory assets (Note 3)	184,351	94,410
Other current assets	39,783	41,849
Total current assets	1,158,385	837,340
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,381,179	1,313,428
Assets for other postretirement benefits (Note 4)	190,306	162,911
Other	129,999	130,859
Total deferred debits	1,701,484	1,607,198
TOTAL ASSETS	$ 16,851,789	$ 15,931,175

The accompanying notes are an integral part of the financial statements.

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ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	September 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,421,696	2,421,696
Retained earnings	2,661,570	2,331,245
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(20,590)	(20,671)
Derivative instruments	(3,026)	(4,752)
Total accumulated other comprehensive loss	(23,616)	(25,423)
Total shareholder equity	5,237,812	4,905,680
Noncontrolling interests (Note 5)	135,539	132,290
Total equity	5,373,351	5,037,970
Long-term debt less current maturities (Note 2)	4,491,048	4,021,785
Total capitalization	9,864,399	9,059,755
CURRENT LIABILITIES		
Short-term borrowings (Note 2)	31,800	135,500
Current maturities of long-term debt (Note 2)	82,000	—
Accounts payable	227,507	259,161
Accrued taxes	233,214	130,576
Accrued interest	48,875	52,525
Common dividends payable	—	72,900
Customer deposits	69,690	82,520
Liabilities from risk management activities (Note 6)	50,469	25,836
Liabilities for asset retirements (Note 14)	1,302	8,703
Regulatory liabilities (Note 3)	120,671	99,899
Other current liabilities	202,524	226,417
Total current liabilities	1,068,052	1,094,037
DEFERRED CREDITS AND OTHER		
Deferred income taxes	3,223,966	2,999,295
Regulatory liabilities (Note 3)	891,715	948,916
Liabilities for asset retirements (Note 14)	660,815	607,234
Liabilities for pension benefits (Note 4)	389,867	488,253
Liabilities from risk management activities (Note 6)	35,775	47,238
Customer advances	101,210	88,672
Coal mine reclamation	222,993	206,645
Deferred investment tax credit	205,870	210,162
Unrecognized tax benefits	43,704	37,408
Other	143,423	143,560
Total deferred credits and other	5,919,338	5,777,383
COMMITMENTS AND CONTINGENCIES (SEE NOTE 7)		
TOTAL LIABILITIES AND EQUITY	$ 16,851,789	$ 15,931,175

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
(dollars in thousands)

	Nine Months Ended September 30, 2017		2016	
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 491,143		$ 418,281	
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization including nuclear fuel	444,439		422,365	
Deferred fuel and purchased power	(43,348	)	(46,185	)
Deferred fuel and purchased power amortization	(18,153	)	28,366	
Allowance for equity funds used during construction	(32,666	)	(31,079	)
Deferred income taxes	202,256		171,000	
Deferred investment tax credit	(4,293	)	(6,342	)
Change in derivative instruments fair value	(254	)	(278	)
Changes in current assets and liabilities:				
Customer and other receivables	(185,130	)	(75,961	)
Accrued unbilled revenues	(44,027	)	(54,291	)
Materials, supplies and fossil fuel	(1,755	)	(4,368	)
Income tax receivable	11,174		—	
Other current assets	(19,100	)	(9,857	)
Accounts payable	(29,784	)	(56,349	)
Accrued taxes	102,638		107,955	
Other current liabilities	11,747		(30,973	)
Change in margin and collateral accounts — assets	(1,826	)	517	
Change in margin and collateral accounts — liabilities	(1,625	)	18,085	

Change in unrecognized tax benefits	5,891		1,628	
Change in other long-term assets	(56,375	)	(54,051	)
Change in other long-term liabilities	(26,049	)	(32,146	)
Net cash flow provided by operating activities	804,903		766,317	
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	(1,008,723	)	(992,735	)
Contributions in aid of construction	24,924		39,355	
Allowance for borrowed funds used during construction	(15,378	)	(14,359	)
Proceeds from nuclear decommissioning trust sales	351,860		447,419	
Investment in nuclear decommissioning trust	(353,001	)	(449,129	)
Other	(18,098	)	(14,016	)
Net cash flow used for investing activities	(1,018,416	)	(983,465	)
CASH FLOWS FROM FINANCING ACTIVITIES				
Issuance of long-term debt	549,478		693,151	
Short-term borrowings and payments — net	(103,700	)	83,300	
Repayment of long-term debt	—		(353,560	)
Dividends paid on common stock	(219,100	)	(208,400	)
Distributions to noncontrolling interests	(11,372	)	(11,372	)
Net cash flow provided by financing activities	215,306		203,119	
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,793		(14,029	)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	8,840		22,056	
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 10,633		$ 8,027	

Supplemental disclosure of cash flow information				
Cash paid during the period for:				
Income taxes, net of refunds	$	132	$	10,533
Interest, net of amounts capitalized	$	142,779	$	144,984
Significant non-cash investing and financing activities:				
Accrued capital expenditures	$	94,769	$	90,069

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(unaudited)
(dollars in thousands)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2016	71,264,947	$178,162	$2,379,696	$2,148,493	$ (27,097)	$ 135,540	$4,814,794
Net income		—	—	403,661	—	14,620	418,281
Other comprehensive income		—	—	—	2,737	—	2,737
Dividends on common stock		—	—	(139,001)	—	—	(139,001)
Net capital activities by noncontrolling interests		—	—	—	—	(11,371)	(11,371)
Balance, September 30, 2016	71,264,947	$178,162	$2,379,696	$2,413,153	$ (24,360)	$ 138,789	$5,085,440
Balance, January 1, 2017	71,264,947	$178,162	$2,421,696	$2,331,245	$ (25,423)	$ 132,290	$5,037,970
Net income		—	—	476,523	—	14,620	491,143
Other comprehensive income		—	—	—	1,807	—	1,807
Other		—	—	—	—	1	1
Dividends on common stock		—	—	(146,198)	—	—	(146,198)
Net capital activities by noncontrolling interests		—	—	—	—	(11,372)	(11,372)
Balance, September 30, 2017	71,264,947	$178,162	$2,421,696	$2,661,570	$ (23,616)	$ 135,539	$5,373,351

The accompanying notes are an integral part of the financial statements.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

The unaudited condensed consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, 4C Acquisition, LLC ("4CA"), Bright Canyon Energy Corporation ("BCE") and El Dorado Investment Company ("El Dorado"). Intercompany accounts and transactions between the consolidated companies have been eliminated. The unaudited condensed consolidated financial statements for APS include the accounts of APS and the Palo Verde Nuclear Generating Station ("Palo Verde") sale leaseback variable interest entities ("VIEs") (see Note 5 for further discussion). Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Amounts reported in our interim Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the respective annual periods, due to the effects of seasonal temperature variations on energy consumption, timing of maintenance on electric generating units, and other factors.

Our condensed consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations, and cash flows for the periods presented. Certain information and footnote disclosures normally included in financial statements prepared in conformity with GAAP have been condensed or omitted pursuant to such regulations, although we believe that the disclosures provided are adequate to make the interim information presented not misleading. The accompanying condensed consolidated financial statements and these notes should be read in conjunction with the audited consolidated financial statements and notes included in our 2016 Form 10-K.

Certain line items are presented in more detail on the company's Condensed Consolidated Statements of Cash Flows than was presented in the prior years. The prior year amounts were reclassified to conform to the current year presentation. These reclassifications have no impact on net cash flows provided by operating activities or financing activities. The following tables show the impacts of the reclassifications of the prior year's (previously reported) amounts (dollars in thousands):

Statements of Cash Flows for the Nine Months Ended September 30, 2016	As previously reported	Reclassifications to conform to current year presentation	Amount reported after reclassification to conform to current year presentation
Cash Flows from Operating Activities			
Stock compensation	$ —	$ 27,588	$ 27,588
Change in other long-term liabilities	(24,839)	(27,588)	(52,427)
Short-term borrowing and payments - net	117,300	(34,000)	83,300
Short-term borrowings under revolving credit facility	—	34,000	34,000

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Cash Flow Information

The following table summarizes supplemental Pinnacle West cash flow information (dollars in thousands):

	Nine Months Ended September 30,	
	2017	2016
Cash paid during the period for:		
Income taxes, net of refunds	$2,185	$2,562
Interest, net of amounts capitalized	147,149	146,691
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$93,031	$91,315

2. Long-Term Debt and Liquidity Matters

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

Pinnacle West

At September 30, 2017, Pinnacle West had a $200 million facility that matures in May 2021. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At September 30, 2017, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $36.6 million of commercial paper borrowings.

On July 31, 2017, Pinnacle West amended its 364-day unsecured revolving credit facility to increase its capacity from $75 million to $125 million, and to extend the termination date of the facility from August 30, 2017 to July 30, 2018. Borrowings under the facility bear interest at LIBOR plus 0.80% per annum. At September 30, 2017, Pinnacle West had $63 million outstanding under the facility.

APS

On March 21, 2017, APS issued an additional $250 million par amount of its outstanding 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance commercial paper borrowings and to replenish cash temporarily used to fund capital expenditures.

On June 29, 2017, APS replaced its $500 million revolving credit facility that would have matured in September 2020, with a new $500 million facility that matures in June 2022.

On September 11, 2017, APS issued $300 million of 2.95% unsecured senior notes that mature on September 15, 2027. The net proceeds from the sale were used to refinance commercial paper and other indebtedness and to replenish cash used to fund capital expenditures.

At September 30, 2017, APS had two revolving credit facilities totaling $1 billion, including a $500 million facility that matures in May 2021 and the above-mentioned $500 million credit facility. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At September 30, 2017, APS had $31.8 million of commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 7 for a discussion of APS's other outstanding letters of credit.

Debt Fair Value

Our long-term debt fair value estimates are based on quoted market prices for the same or similar issues, and are classified within Level 2 of the fair value hierarchy. Certain of our debt instruments contain third-party credit enhancements and, in accordance with GAAP, we do not consider the effect of these credit enhancements when determining fair value. The following table presents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of September 30, 2017		As of December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$125,000	$125,000	$125,000	$125,000
APS	4,573,048	4,938,258	4,021,785	4,300,789
Total	$4,698,048	$5,063,258	$4,146,785	$4,425,789

Debt Provisions

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At September 30, 2017, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $5.2 billion, and total capitalization was approximately $10.0 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $4.0 billion, assuming APS's total capitalization remains the same.

3. Regulatory Matters

Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excluded amounts that were then collected on customer bills through adjustor mechanisms. The application requested that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have had an incremental effect on average customer bills. The average annual customer bill impact of APS's request was an increase of 5.74% (the average annual bill impact for a typical APS residential customer was 7.96%). The principal provisions of the application are described in detail in Note 3 of our 2016 Form 10-K.

On March 27, 2017, a majority of the stakeholders in the rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations signed a

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules. The average annual customer bill impact under the 2017 Settlement Agreement is an increase of 3.28% (the average annual bill impact for a typical APS residential customer is 4.54%).

Other key provisions of the agreement include the following:

- an agreement by APS not to file another general rate case application before June 1, 2019;
- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general rate case related to its share of the construction costs associated with installing selective catalytic reduction ("SCR") equipment at the Four Corners Power Plant ("Four Corners");
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the Power Supply Adjustor ("PSA") to include certain environmental chemical costs and third-party battery storage costs;
- a new AZ Sun II program for utility-owned solar distributed generation with the purpose of expanding access to rooftop solar for low and moderate income Arizonans, recoverable through the Arizona Renewable Energy Standard and Tariff ("RES"), to be no less than $10 million per year, and not more than $15 million per year;
- an increase to the per kilowatt-hour ("kWh") cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
  - a change in the on-peak time of use period from noon - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
  - non-grandfathered distributed generation customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
  - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

Through a separate agreement, APS, industry representatives, and solar advocates committed to stand by the settlement agreement and refrain from seeking to undermine it through ballot initiatives, legislation or advocacy at the ACC.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On August 15, 2017, the ACC approved (by a vote of 4-1), the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case, which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017. On August 20, 2017, Commissioner Burns filed a special action petition in the Arizona Supreme Court seeking to vacate the ACC's order approving the 2017 Settlement Agreement so that alleged issues of disqualification and bias on the part of the other Commissioners can be fully investigated. APS opposed the petition, and on October 17, 2017, the Arizona Supreme Court declined to accept jurisdiction over Commissioner Burns' special action petition.

On October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. APS cannot predict the outcome of this appeal but does not believe it will have a material impact.

Prior Rate Case Filing

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into an agreement (the "2012 Settlement Agreement") detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

The 2012 Settlement Agreement provides for a zero net change in base rates, consisting of: (1) a non-fuel base rate increase of $116.3 million; (2) a fuel-related base rate decrease of $153.1 million (to be implemented by a change in the base fuel rate for fuel and purchased power costs ("Base Fuel Rate") from $0.03757 to $0.03207 per kWh; and (3) the transfer of cost recovery for certain renewable energy projects from the RES surcharge to base rates in an estimated amount of $36.8 million. Other key provisions of the 2012 Settlement Agreement are described in detail in Note 3 of our 2016 Form 10-K.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget.

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The costs for this program have been included in APS's rate base as part of the 2017 rate case decision.

On July 1, 2015, APS filed its 2016 RES Implementation Plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which included the revenue neutral transfer of specific revenue requirements in accordance with the 2017 Settlement Agreement. On August 15, 2017, the ACC approved the 2017 RES Implementation Plan.

On June 30, 2017, APS filed its 2018 RES Implementation Plan and proposed a budget of approximately $90 million. APS's budget request supports existing approved projects and commitments and includes the anticipated transfer of specific revenue requirements in accordance with the 2017 Settlement Agreement and also requests a permanent waiver of the residential distributed energy requirement for 2018 contained in the RES rules. APS's 2018 RES budget request is lower than the 2017 RES budget due in part to a certain portion of the RES being collected by APS in base rates rather than through the RES adjustor. The ACC has not yet ruled on APS's 2018 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. The ACC noted that many of the provisions of the original rule may no longer be appropriate, and the underlying economic assumptions associated with the rule have changed dramatically. The proceeding will review such issues as the rapidly declining cost of solar generation, an increased interest in community solar projects, energy storage options, and the decline in fossil fuel generation due to stringent regulations of the United States Environmental Protection Agency ("EPA"). The proceeding will also examine the feasibility of increasing the standard to 30% of retail sales by 2030, in contrast to the current standard of 15% of retail sales by 2025. APS cannot predict the outcome of this proceeding.

Demand Side Management Adjustor Charge ("DSMAC"). The ACC Electric Energy Efficiency Standards require APS to submit a Demand Side Management Implementation Plan ("DSM Plan") annually for review by and approval of the ACC. On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also ruled that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard; however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from conservation voltage reduction in the calculation of its Lost Fixed Cost Recovery Mechanism ("LFCR") mechanism.

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. On April 1, 2016, APS filed an amended 2016 DSM Plan that sought minor modifications to its existing DSM Plan and requested to continue the current DSMAC and current budget of $68.9 million. On August 5, 2016, the ACC approved APS's amended DSM Plan and directed APS to spend up to an additional $4 million on a new

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residential demand response or load management program that facilitates energy storage technology. On December 5, 2016, APS filed for ACC approval of a $4 million Residential Demand Response, Energy Storage and Load Management Program.

On June 1, 2016, APS filed its 2017 DSM Implementation Plan, in which APS proposed programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Implementation Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed Residential Demand Response, Energy Storage and Load Management Program and the requested budget be increased to $66.6 million. On August 15, 2017, the ACC approved the 2017 DSM Plan.

On September 1, 2017, APS filed its 2018 DSM Implementation Plan, which proposes modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Implementation Plan seeks a reduced budget of $52.6 million and requests a waiver of the energy efficiency standard for 2018.

Electric Energy Efficiency. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. On July 12, 2016, the ACC ordered that ACC staff convene a workshop within 120 days to discuss a number of issues related to the Electric Energy Efficiency Standards, including the process of determining the cost effectiveness of DSM programs and the treatment of peak demand and capacity reductions, among others. ACC staff convened the workshop on November 29, 2016 and sought public comment on potential revisions to the Electric Energy Efficiency Standards. APS cannot predict the outcome of this proceeding.

PSA Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2017 and 2016 (dollars in thousands):

	Nine Months Ended September 30,	
	2017	2016
Beginning balance	$12,465	$(9,688)
Deferred fuel and purchased power costs — current period	43,348	46,185
Amounts refunded/(charged) to customers	18,153	(28,365)
Ending balance	$73,966	$8,132

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The PSA rate for the PSA year beginning February 1, 2017 was $(0.001348) per kWh, as compared to $0.001678 per kWh for the prior year. This rate was comprised of a forward component of $(0.001027) per kWh and a historical component of $(0.000321) per kWh. On August 19, 2017 the PSA rate was revised to $0.000555 per kWh. This new rate is comprised of a forward component of $0.000876 per kWh and a historical component of $(0.000321) per kWh.

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, the United States Federal Energy Regulatory Commission ("FERC") approved an Open Access Transmission Tariff for APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the 2012 Settlement Agreement, however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. APS reviews the proposed formula rate filing amounts with the ACC staff. Any items or adjustments which are not agreed to by APS and the ACC staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts.

Effective June 1, 2016, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $24.9 million for the twelve-month period beginning June 1, 2016 in accordance with the FERC-approved formula. An adjustment to APS’s retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2016.

Effective June 1, 2017, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $35.1 million for the twelve-month period beginning June 1, 2017 in accordance with the FERC-approved formula. An adjustment to APS’s retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2017.

On January 31, 2017, APS made a filing to reduce the Post-Employment Benefits Other than Pension expense reflected in its FERC transmission formula rate calculation to recognize certain savings resulting from plan design changes to the other postretirement benefit plans. A transmission customer intervened and protested certain aspects of APS’s filing. FERC initiated a proceeding under Section 206 of the Federal Power Act to evaluate the justness and reasonableness of the revised formula rate filing APS proposed. APS entered into a settlement agreement with the intervening transmission customer, which was filed with FERC for approval on September 26, 2017. The proceeding is still pending before FERC. At this time, APS is unable to predict the outcome of this proceeding.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to distributed generation such as rooftop solar arrays. The fixed

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costs recoverable by the LFCR mechanism were established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWh's lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. Distributed generation sales losses are determined from the metered output from the distributed generation units.

APS filed its 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase). The ACC approved the 2016 annual LFCR effective beginning in May 2016. APS filed its 2017 LFCR adjustment on January 13, 2017 requesting an LFCR adjustment of $63.7 million (a $17.3 million per year increase over 2016 levels). On April 5, 2017, the ACC approved the 2017 annual LFCR adjustment as filed, effective with the first billing cycle of April 2017. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, a one or two month delay in implementation does not have an adverse effect on APS.

Tax Expense Adjustor Mechanism ("TEAM"). As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform. In the event that federal income tax reform legislation is enacted and effective prior to the conclusion of APS's next general rate case, and such legislation impacts APS's annual revenue requirement by more than $5 million, the TEAM enables the pass-through of certain income tax effects to customers. The impact to APS's annual revenue requirement will be measured as the change in income tax expense resulting from any change to the statutory rate, the annual amortization of any resulting excess deferred income taxes, and/or the tax effects of any permanent income tax adjustments that may be included in the enacted legislation (such as limitations on interest deductibility).

Net Metering

In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, the Administrative Law Judge issued a recommendation in the docket concerning the value and cost of distributed generation ("DG") solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended decision by the Administrative Law Judge. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC's action, effective as of APS's 2017 rate case decision, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a resource comparison proxy methodology, a method that is based on the price that APS pays for utility-scale solar projects on a five year rolling average, while a forecasted avoided cost methodology is being developed. The price established by this resource comparison proxy method will be updated annually (between rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior August 19, 2017, the date new rates were effective based on APS's 2017 rate case, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh is included in the 2017 Settlement Agreement and became effective on August 19, 2017.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

System Benefits Charge

The 2012 Settlement Agreement provided that once APS achieved full funding of its decommissioning obligation under the sale leaseback agreements covering Unit 2 of Palo Verde, APS was required to implement a reduced System Benefits charge effective January 1, 2016. Beginning on January 1, 2016, APS began implementing a reduced System Benefits charge. The impact on APS retail revenues from the new System Benefits charge is an overall reduction of approximately $14.6 million per year with a corresponding reduction in depreciation and amortization expense. This adjustment is subsumed within the 2017 Settlement Agreement and its associated revenue requirement.

Subpoena from Arizona Corporation Commissioner Robert Burns

On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, filed subpoenas in APS's then current retail rate proceeding to APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns’ subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Commissioner Burns filed suit against APS and Pinnacle West in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Commissioner Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel. On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself. All defendants have moved to dismiss the complaint. Oral argument at the Superior Court of Arizona for Maricopa County is scheduled for December 19, 2017. APS and Pinnacle West cannot predict the outcome of this matter.

In addition to the Superior Court of Arizona for Maricopa County proceedings discussed above, on August 20, 2017, Commissioner Burns filed a special action petition in the Arizona Supreme Court seeking to vacate the ACC's order approving the settlement so that alleged issues of disqualification and bias on the part of the other Commissioners can be fully investigated. APS opposed the petition, and on October 17, 2017, the Arizona Supreme Court declined to accept jurisdiction over Commissioner Burns’ special action petition.

Four Corners

On December 30, 2013, APS purchased Southern California Edison Company's ("SCE’s") 48% ownership interest in each of Units 4 and 5 of Four Corners. The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general rate case related to APS’s acquisition of the additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This includes the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE’s interest in Units 4 and 5 and the closure of Units 1-3 was $58 million as of September 30, 2017 and is being amortized in rates over a total of 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the System Improvement Benefits ("SIB") matter. The Arizona Court of Appeals reversed an ACC rate decision involving a water company regarding the ACC's method of finding fair value in that case, which raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the

Arizona Supreme Court of this decision and, on August 8, 2016, the Arizona Supreme Court vacated the Court of Appeals opinion and affirmed the ACC’s orders approving the water company’s SIB adjustor. The Arizona Court of Appeals ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. Supplemental briefing has been completed and the Arizona Court of Appeals heard oral argument on this matter on September 14, 2017. On September 26, 2017, the Court of Appeals affirmed the ACC's decision on the Four Corners rate adjustment.

As part of APS’s acquisition of SCE’s interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS’s request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed a request for rehearing with FERC. In its order denying recovery FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS is currently considering next steps and cannot predict whether or if the enforcement division will take any action.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of the Cholla Power Plant ("Cholla") and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017.
Previously, APS estimated Cholla Unit 2’s end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit’s decommissioning and other retirement-related costs ($109 million as of September 30, 2017), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2’s remaining net book value was reclassified from property, plant and equipment to a regulatory asset.

Navajo Plant

The co-owners of the Navajo Generating Station (the "Navajo Plant") and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease, at which time a new lease will allow for decommissioning activities to begin after December 2019 instead of later this year. The new lease was approved by the Navajo Nation Tribal Council on June 26, 2017. Certain additional approvals are required for specific co-owners, which are expected to occur by late 2017. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the U.S. Department of the Interior have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the Navajo Plant will cease operations in December 2019.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($102 million as of September 30, 2017) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. APS believes it will be allowed recovery of the net book value, in addition to a return on its investment. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of this interest, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in thousands):

	Amortization	September 30, 2017		December 31, 2016	
	Through	Current	Non-Current	Current	Non-Current
Pension	(a)	$—	$ 686,511	$—	$ 711,059
Retired power plant costs	Various	28,647	194,639	9,913	117,591
Income taxes — allowance for funds used during construction ("AFUDC") equity	2047	6,202	170,622	6,305	152,118
Deferred fuel and purchased power — mark-to-market (Note 6)	2020	45,463	33,115	—	42,963
Deferred fuel and purchased power (b) (d)	2018	73,966	—	12,465	—
Four Corners cost deferral	2024	8,077	50,324	6,689	56,894
Income taxes — investment tax credit basis adjustment	2046	2,120	53,225	2,120	54,356
Lost fixed cost recovery (b)	2018	67,500	—	61,307	—
Palo Verde VIEs (Note 5)	2046	—	19,240	—	18,775
Deferred compensation	2036	—	37,265	—	35,595
Deferred property taxes	2027	8,569	77,408	—	73,200
Loss on reacquired debt	2038	1,637	15,715	1,637	16,942
Tax expense of Medicare subsidy	2024	1,503	9,074	1,513	10,589
Demand Side Management	2018	—	—	3,744	—
AG-1 deferral	2022	2,654	9,136	—	5,868
Mead-Phoenix transmission line CIAC	2050	332	10,459	332	10,708
Transmission cost adjustor (b)	2018	4,345	—	—	1,588
Coal reclamation	2026	1,068	14,446	418	5,182
Other	Various	6,234	—	432	—
Total regulatory assets (c)		$258,317	$ 1,381,179	$106,875	$ 1,313,428

(a) See Note 4 for further discussion.

(b) See "Cost Recovery Mechanisms" discussion above.

(c) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."

(d) Subject to a carrying charge.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The detail of regulatory liabilities is as follows (dollars in thousands):

	Amortization Through	September 30, 2017		December 31, 2016	
		Current	Non-Current	Current	Non-Current
Asset retirement obligations	2057	$—	$ 313,189	$—	$ 279,976
Removal costs	(a)	37,756	184,512	29,899	223,145
Other postretirement benefits	(b)	32,725	99,626	32,662	123,913
Income taxes — deferred investment tax credit	2046	4,315	106,557	4,368	108,827
Income taxes — change in rates	2046	2,565	67,136	1,771	70,898
Spent nuclear fuel	2027	6,562	64,504	—	71,726
Renewable energy standard (c)	2018	17,915	—	26,809	—
Demand side management (c)	2019	12,175	4,921	—	20,472
Sundance maintenance	2030	—	16,494	—	15,287
Deferred gains on utility property	2022	4,525	11,875	2,063	8,895
Four Corners coal reclamation	2031	1,857	19,494	—	18,248
Other	Various	276	3,407	2,327	7,529
Total regulatory liabilities		$120,671	$ 891,715	$99,899	$ 948,916

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal.
(b) See Note 4 for further discussion.
(c) See "Cost Recovery Mechanisms" discussion above.

4. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a non-qualified supplemental excess benefit retirement plan, and an other postretirement benefit plan for the employees of Pinnacle West and our subsidiaries. Pinnacle West uses a December 31 measurement date for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement dates. Because of plan changes in September 2014, the Company is currently in the process of seeking IRS approval to move approximately $145 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs. In December 2016, FERC approved a methodology for determining the amount of other postretirement benefit trust assets to transfer into a new trust account to pay for active union employee medical costs. While we do not expect to transfer any funds prior to 2018, as of September 30, 2017, such methodology would result in an amount of approximately $145 million being transferred to the new trust account.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants) (dollars in thousands):

	Pension Benefits Three Months Ended September 30,		Nine Months Ended September 30,		Other Benefits Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016	2017	2016	2017	2016
Service cost — benefits earned during the period	$13,715	$13,448	$41,144	$40,344	$4,280	$3,748	$12,839	$11,245
Interest cost on benefit obligation	32,439	32,912	97,316	98,735	7,490	7,430	22,470	22,291
Expected return on plan assets	(43,568)	(43,477)	(130,703)	(130,429)	(13,350)	(9,123)	(40,051)	(27,371)
Amortization of:								
Prior service cost (credit)	20	132	61	395	(9,461)	(9,471)	(28,382)	(28,413)
Net actuarial loss	11,975	10,179	35,924	30,538	1,279	1,147	3,838	3,442
Net periodic benefit cost	$14,581	$13,194	$43,742	$39,583	$(9,762)	$(6,269)	$(29,286)	$(18,806)
Portion of cost charged to expense	$7,231	$6,476	$21,692	$19,427	$(4,841)	$(3,077)	$(14,523)	$(9,230)

See ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost in Note 12 for additional information.

Contributions

We have made voluntary contributions of $100 million to our pension plan year-to-date in 2017. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2017-2019 period. We expect to make contributions of less than $1 million in total for the next three years to our other postretirement benefit plans.

5. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. APS will retain the assets through 2023 under one lease and 2033 under the other two leases. APS will be required to make payments relating to these leases of approximately $23 million annually through 2023, and $16 million annually for the period 2024 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

The leases' terms give APS the ability to utilize the assets for a significant portion of the assets' economic life, and therefore provide APS with the power to direct activities of the VIEs that most significantly impact the VIEs' economic performance. Predominantly due to the lease terms, APS has been deemed the primary beneficiary of these VIEs and therefore consolidates the VIEs.

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income for the three and nine months ended September 30, 2017 of $5 million and $15 million, respectively, and for the three and nine months ended September 30, 2016 of $5 million and $15 million, respectively, entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Condensed Consolidated Balance Sheets at September 30, 2017 and December 31, 2016 include the following amounts relating to the VIEs (dollars in thousands):

	September 30, 2017	December 31, 2016
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$ 110,613	$ 113,515
Equity — Noncontrolling interests	135,539	132,290

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our condensed consolidated financial statements.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the Nuclear Regulatory Commission ("NRC") issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $291 million beginning in 2017, and up to $456 million over the lease terms.

For regulatory ratemaking purposes, the agreements continue to be treated as operating leases and, as a result, we have recorded a regulatory asset relating to the arrangements.

6. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. Risks associated with market volatility are managed by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power costs in our Condensed Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheet as an asset or liability and are measured at fair value. See Note 10 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below. Cash flow hedge accounting was discontinued for the significant majority of our contracts after May 31, 2012.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 3). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of September 30, 2017 and December 31, 2016, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Unit of Measure	Quantity September 30, 2017	 December 31, 2016
Power	GWh	736	1,314
Gas	Billion cubic feet	205	194

Gains and Losses from Derivative Instruments

The following table provides information about gains and losses from derivative instruments in designated cash flow accounting hedging relationships during the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Three Months Ended September 30, 2017	 2016	Nine Months Ended September 30, 2017	 2016
Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ 14	$ (47)	$ (70)	$ 13
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(1,148)	(1,298)	(2,910)	(3,255)

(a) During the three and nine months ended September 30, 2017 and 2016, we had no losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.
(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that a net loss of $2 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

	Financial Statement Location	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts		2017	2016	2017	2016
Net Gain (Loss) Recognized in Income	Operating revenues	$(128)	$41	$(474)	$524
Net Loss Recognized in Income	Fuel and purchased power (a)	(6,100)	(35,103)	(64,143)	(5,145)
Total		$(6,228)	$(35,062)	$(64,617)	$(4,621)

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Condensed Consolidated Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Condensed Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Condensed Consolidated Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. Additionally, in the event of a default, our master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The significant majority of our derivative instruments are not currently designated as hedging instruments. The Condensed Consolidated Balance Sheets as of September 30, 2017 and December 31, 2016, include gross liabilities of $0.4 million and $2 million, respectively, of derivative instruments designated as hedging instruments.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following tables provide information about the fair value of our risk management activities reported on a gross basis, and the impacts of offsetting as of September 30, 2017 and December 31, 2016. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of our Condensed Consolidated Balance Sheets.

As of September 30, 2017: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 9,764	$ (9,623)	$ 141	$ 217	$ 358
Investments and other assets	2,137	(2,053)	84	1,608	1,692
Total assets	11,901	(11,676)	225	1,825	2,050
Current liabilities	(57,663)	9,623	(48,040)	(2,429)	(50,469)
Deferred credits and other	(37,828)	2,053	(35,775)	—	(35,775)
Total liabilities	(95,491)	11,676	(83,815)	(2,429)	(86,244)
Total	$ (83,590)	$ —	$ (83,590)	$ (604)	$ (84,194)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral, cash margin and option premiums that are not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $2,429, cash margin provided to counterparties of $217 and option premiums of $1,608.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2016: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 48,094	$ (28,400)	$ 19,694	$ —	$ 19,694
Investments and other assets	6,704	(6,703)	1	—	1
Total assets	54,798	(35,103)	19,695	—	19,695
Current liabilities	(50,182)	28,400	(21,782)	(4,054)	(25,836)
Deferred credits and other	(53,941)	6,703	(47,238)	—	(47,238)
Total liabilities	(104,123)	35,103	(69,020)	(4,054)	(73,074)
Total	$ (49,325)	$ —	$ (49,325)	$ (4,054)	$ (53,379)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $4,054.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of September 30, 2017, Pinnacle West has no counterparties with positive exposures of greater than 10% of risk management assets. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor’s or Fitch or Baa3 for Moody’s).

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information about our derivative instruments that have credit-risk-related contingent features at September 30, 2017 (dollars in thousands):

	September 30, 2017
Aggregate fair value of derivative instruments in a net liability position	$ 95,491
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	81,866

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $118 million if our debt credit ratings were to fall below investment grade.

7. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE’s breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS’s share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of reported net income. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019.

APS has submitted three claims pursuant to the terms of the August 18, 2014 settlement agreement, for three separate time periods during July 1, 2011 through June 30, 2016. The DOE has approved and paid $65.2 million for these claims (APS’s share is $19 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 retail rate case settlement, this regulatory liability is being refunded to customers (see Note 3). APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement will be submitted to the DOE in the fourth quarter of 2017, and payment is expected in the second quarter of 2018.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $13.4 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $13.0 billion of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to a maximum annual premium of $19 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $111.1 million, with a maximum annual retrospective premium of approximately $16.6 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $24 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $64.8 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

Contractual Obligations

For the nine months ended September 30, 2017, our fuel and purchased power commitments decreased approximately $1 billion from amounts reported at December 31, 2016 primarily due to updated estimated renewable energy purchases. The majority of these changes relate to the years 2022 and thereafter.
Other than the items described above, there have been no material changes, as of September 30, 2017, outside the normal course of business in contractual obligations from the information provided in our 2016 Form 10-K. See Note 2 for discussion regarding changes in our long-term debt obligations.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS, APS anticipates finalizing the RI/FS in spring 2018. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID’s groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS’s current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS’s current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID contractors filed ancillary lawsuits for recovery of costs against APS and the other defendants. In addition, on March 15, 2017, the Arizona District Court granted partial summary judgment to RID for one element of RID's lawsuit against APS and the other defendants. On May 12, 2017, the court denied a motion for reconsideration as to this order. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing new pollution control requirements on Four Corners and the Navajo Plant. EPA will require these plants to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plants. EPA approved a proposed rule for Regional Haze compliance at Cholla that

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does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the Cholla BART approval.

Four Corners. Based on EPA's final standards, APS estimates that its 63% share of the cost of required controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso Electric Company ("El Paso") entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company, LLC ("NTEC") has the option to purchase the interest within a certain timeframe pursuant to an option granted to NTEC. In December 2015, NTEC notified APS of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. The parties are currently in discussions as to the future of the option transaction. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's Federal Implementation Plan ("FIP"), could be up to approximately $200 million; however, given the future plans for the Navajo Plant, we do not expect to incur these costs. See "Navajo Plant" in Note 3 for information regarding future plans for the Navajo Plant.

Cholla. APS believed that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of SCR controls, was unsupported and that EPA had no basis for disapproving Arizona's State Implementation Plan ("SIP") and promulgating a FIP that was inconsistent with the state's considered BART determinations under the regional haze program. In September 2014, APS met with EPA to propose a compromise BART strategy. APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP.

On October 16, 2015, ADEQ issued a revised operating permit for Cholla, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. On June 30, 2016, EPA issued a proposed rule approving a revision to the Arizona SIP that incorporates APS's compromise approach for compliance with the Regional Haze program. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation ("WIIN") Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds.

ADEQ has initiated a process to evaluate how to develop a state CCR permitting program that would cover electric generating units ("EGUs"), including Cholla. While APS has been working with ADEQ on the development of this program, we are unable to predict when Arizona will be able to finalize and secure EPA approval for a state-specific CCR permitting program. With respect to the Navajo Nation, APS recently filed a comment letter with EPA seeking clarification as to when and how EPA would be initiating permit proceedings for facilities on the reservation, including Four Corners. We are unable to predict at this time when EPA will be issuing CCR management permits for the facilities on the Navajo Nation. At this time, it remains unclear how the CCR provisions of the WIIN Act will affect APS and its management of CCR.

Based upon utility industry petitions for EPA to reconsider the RCRA Subtitle D regulations for CCR, which were premised in part on the CCR provisions of the 2016 WIIN Act, on September 13, 2017 EPA agreed to evaluate whether to revise these federal CCR regulations. At this time, it is not clear whether the EPA will initiate further notice-and-comment rulemaking to revise the federal CCR rules, nor is it clear what aspects of the federal CCR rules might be changed as a result of this process. With respect to ongoing litigation initiated by industry and environmental groups challenging the legality of these federal CCR regulations, on September 27, 2017 the United States Court of Appeals for the D.C. Circuit, the court overseeing these judicial challenges, ordered EPA to file by November 15, 2017 a list of federal regulatory provisions addressing CCR that are or likely will be revised through EPA's reconsideration proceedings.

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA's CCR regulations, within the next two years EPA is required to complete a rulemaking proceeding concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA's CCR rules. EPA is not required to take final action approving the inclusion of boron, but EPA must propose and consider its inclusion. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time APS cannot predict when EPA will commence its rulemaking concerning boron or the eventual results of those proceedings.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $20 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. By October 17, 2017, electric utility companies that own or operate CCR disposal units, such as APS, must have collected sufficient groundwater sampling data to initiate a detection monitoring program. To the extent that certain threshold constituents are identified through this initial detection monitoring at levels above the CCR rule's standards, the rule requires the initiation of an assessment monitoring program by April 15, 2018. If this assessment monitoring program reveals concentrations of certain constituents above the CCR rule standards that trigger remedial obligations, a corrective measures evaluation must be completed by October 12, 2018. Depending upon the results of such groundwater monitoring and data evaluations at each of Cholla, Four Corners and the Navajo Plant, we may be required to take corrective actions, the costs of which we are unable to reasonably estimate at this time.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for EGUs. Shortly thereafter, a coalition of states, industry groups and electric utilities challenged the legality of these standards, including EPA's Clean Power Plan for existing EGUs, in the U.S. Court of Appeals for the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. On March 28, 2017, President Trump issued an Executive Order that, among other things, instructs EPA to reevaluate Agency regulations concerning carbon emissions from EGUs and take appropriate action to suspend, revise or rescind the August 2015 carbon pollution standards for EGUs, including the Clean Power Plan. Also on March 28, 2017, the U.S. Department of Justice, on behalf of EPA, filed a motion with the U.S. Court of Appeals for the D.C. Circuit Court to hold the ongoing litigation over the Clean Power Plan in abeyance pending EPA action in accordance with the Executive Order. This motion was granted on April 28, 2017 by an order that held the case in abeyance for 60 days to give the litigation parties an opportunity to brief the Court as to whether to remand the proceedings back to EPA. On August 8, 2017, the Court extended the abeyance period for an additional 60 days, instructed EPA to file status updates with the Court every 30 days thereafter, and reminded EPA that it has an affirmative statutory obligation to regulate greenhouse gas emissions, based on EPA's 2009 endangerment finding as to such emissions.

Based upon EPA's reevaluation of the August 2015 carbon pollution standards and the legal basis for these regulations, on October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan. In its proposal, EPA states that it will issue in the near future an Advanced Notice of Proposed Rulemaking by which EPA will solicit comments as to potential replacements for the Clean Power Plan that would be consistent with EPA's current legal interpretation of the Clean Air Act. In accordance with the D.C. Circuit Court's August 8, 2017 order (described above) regarding the ongoing Clean Power Plan litigation, the U.S. Department of Justice notified the Court of EPA's repeal proposal.

We cannot predict the outcome of EPA's regulatory actions related to the August 2015 carbon pollution standards for EGU's, including any actions related to the EPA's repeal proposal for the Clean Power Plan or additional rulemaking actions to develop regulations replacing the Clean Power Plan. In addition, we cannot predict whether the D.C. Circuit Court will continue to hold the litigation challenging the original Clean Power Plan in abeyance in light of EPA's repeal proposal. The carbon pollution standards for EGUs on state and tribal lands are described in detail in Note 10 of our 2016 Form 10-K.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

Federal Agency Environmental Lawsuit Related to Four Corners

On April 20, 2016, several environmental groups filed a lawsuit against the Office of Surface Mining Reclamation and Enforcement ("OSM") and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. The environmental group plaintiffs have until November 13, 2017 to file an appeal of this dismissal order with the Ninth Circuit Court of Appeals. We cannot predict whether the plaintiffs will appeal the order or whether such appeal, if filed, will be successful.

Four Corners Coal Supply Agreement

Arbitration

On June 13, 2017, APS received a Demand for Arbitration from NTEC in connection with the 2016 Coal Supply Agreement, dated December 30, 2013, under which NTEC supplies coal to APS and the other Four Corners owners (collectively, the “Buyer”) for use at the Four Corners Power Plant. NTEC was originally seeking a declaratory judgment to support its interpretation of a provision regarding uncontrollable forces in the agreement that relates to annual minimum quantities of coal to be purchased by the Buyer. NTEC also alleged a shortfall in the Buyer’s purchases for the initial contract year of approximately $30 million. APS’s share of this amount is approximately $17 million. On September 20, 2017, NTEC amended its Demand for Arbitration removing its request for a declaratory judgment and at this time is only seeking relief for the alleged shortfall in the Buyer's purchases for the initial contract year. We cannot predict the timing or outcome of this arbitration; however we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

4CA Matter

On July 6, 2016, 4CA purchased El Paso’s 7% interest in Four Corners. NTEC has the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. The parties are currently in discussions as to the future of the option transaction.

The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% interest in the event NTEC does not purchase the interest. At this time, since NTEC has not yet purchased the 7% interest, the alternate pricing provisions are applicable to 4CA as the holder of the 7% interest. These terms include a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. Such payments are due to 4CA at the end of each calendar year. The balance of this amount at September 30, 2017 is approximately $26 million, $10 million of which is due to 4CA at December 31, 2017. 4CA believes NTEC should satisfy its contractual obligations related to these payments; however, if NTEC fails to meet its contractual obligations when due, 4CA will consider appropriate measures and potential impacts to the Company's financial statements.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support certain debt arrangements, commodity contract collateral obligations, and other transactions. As of September 30, 2017, standby letters of credit totaled $5 million and will expire in 2018. As of September 30, 2017, surety bonds expiring through 2019 totaled $62 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at September 30, 2017. Since July 6, 2016, Pinnacle West has issued four parental guarantees for 4CA relating to payment obligations arising from 4CA's acquisition of El Paso's 7% interest in Four Corners, and pursuant to the Four Corners participation agreement payment obligations arising from 4CA's ownership interest in Four Corners.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

8. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Other income:				
Interest income	$917	$65	$1,782	$370
Investment gains — net	119	—	119	13
Miscellaneous	55	6	154	2
Total other income	$1,091	$71	$2,055	$385
Other expense:				
Non-operating costs	$(1,978)	$(2,502)	$(7,338)	$(6,636)
Investment losses — net	(231)	(450)	(759)	(1,508)
Miscellaneous	(2,784)	(2,253)	(4,398)	(3,941)
Total other expense	$(4,993)	$(5,205)	$(12,495)	$(12,085)

The following table provides detail of APS's other income and other expense for the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Other income:				
Interest income	$683	$—	$1,278	$181
Gain on disposition of property	441	183	1,009	5,504
Miscellaneous	354	384	1,395	1,239
Total other income	$1,478	$567	$3,682	$6,924
Other expense:				
Non-operating costs (a)	$(1,970)	$(2,714)	$(7,889)	$(7,398)
Loss on disposition of property	(3,214)	36	(4,471)	(1,048)
Miscellaneous	(1,078)	(1,098)	(3,930)	(4,510)
Total other expense	$(6,262)	$(3,776)	$(16,290)	$(12,956)

(a) As defined by FERC, includes below-the-line non-operating utility expense (items excluded from utility rate recovery).

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

9. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for the three and nine months ended September 30, 2017 and 2016 (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income attributable to common shareholders	$276,072	$263,027	$466,827	$388,788
Weighted average common shares outstanding — basic	111,835	111,416	111,787	111,363
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	566	684	527	624
Weighted average common shares outstanding — diluted	112,401	112,100	112,314	111,987
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$2.47	$2.36	$4.18	$3.49
Net income attributable to common shareholders — diluted	$2.46	$2.35	$4.16	$3.47

10. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities that we have the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide information on an ongoing basis. This category includes exchange traded equities, exchange traded derivative instruments, exchange traded mutual funds, cash equivalents, and investments in U.S. Treasury securities.

Level 2 — Utilizes quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active; and model-derived valuations whose inputs are observable (such as yield curves). This category includes non-exchange traded contracts such as forwards, options, swaps and certain investments in fixed income securities.

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs

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may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of Net Asset Value (“NAV”), as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, they are not traded on an exchange. Instruments valued using NAV, as a practical expedient, are included in our fair value disclosures however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, investments held in coal reclamation escrow accounts, derivative instruments, investments held in our nuclear decommissioning trust, plan assets held in our retirement and other benefit plans. See Note 7 in the 2016 Form 10-K for the fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent short-term investments with original maturities of three months or less in exchange traded money market funds that are valued using quoted prices in active markets.

Coal Reclamation Escrow Account

Coal reclamation escrow account represents investments restricted for coal mine reclamation funding related to Four Corners. The account investments may include fixed income instruments such as municipal bond securities and cash equivalents. Fixed income securities are classified as Level 2 and are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. Cash equivalents are classified as Level 1 and are valued as described above.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions.

Our energy risk management committee, consisting of officers and key management personnel, oversees our energy risk management activities to ensure compliance with our stated energy risk management policies. We have a risk control function that is responsible for valuing our derivative commodity instruments in accordance with established policies and procedures. The risk control function reports to the chief financial officer's organization.

Investments Held in our Nuclear Decommissioning Trust

The nuclear decommissioning trust invests in fixed income securities and equity securities. Equity securities are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

Cash equivalents reported within Level 1 represent investments held in a short-term investment exchange-traded mutual fund, which invests in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, and commercial paper.

Fixed income securities issued by the U.S. Treasury held directly by the nuclear decommissioning trust are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes. See Note 11 for additional discussion about our nuclear decommissioning trust.

Fair Value Tables

The following table presents the fair value at September 30, 2017, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at September 30, 2017
Assets						
Coal reclamation escrow account (b):						
Cash equivalents	$ 7,175	$—	$ —	$510		$7,685
Municipal bonds	—	24,973	—	—		24,973
Risk management activities — derivative instruments:						
Commodity contracts	—	8,429	3,472	(9,851)	(c)	2,050
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	—	—	401,913	(d)	401,913
Fixed income securities:						
Cash and cash equivalent funds	10,598	—	—	4,378	(e)	14,976
U.S. Treasury	90,776	—	—	—		90,776
Corporate debt	—	124,369	—	—		124,369
Mortgage-backed securities	—	116,237	—	—		116,237
Municipal bonds	—	76,412	—	—		76,412
Other	—	17,297	—	—		17,297
Subtotal nuclear decommissioning trust	101,374	334,315	—	406,291		841,980
Total	$ 108,549	$367,717	$ 3,472	$396,950		$876,688
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(53,414)	$ (42,077)	$9,247	(c)	$(86,244)

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(a) Primarily consists of long-dated electricity contracts.
(b) Represents investments restricted for coal mine reclamation funding related to Four Corners. These assets are included in the Other Assets line item, reported under the Investments and Other Assets section of our Condensed Consolidated Balance Sheets. Coal reclamation escrow account was presented as Coal reclamation trust in 2016.
(c) Represents counterparty netting, margin, collateral and option premiums. See Note 6.
(d) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(e) Represents nuclear decommissioning trust net pending securities sales and purchases.

The following table presents the fair value at December 31, 2016, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at December 31, 2016
Assets						
Coal reclamation trust - cash equivalents (b):	$ 14,521	$—	$ —	$—		$ 14,521
Risk management activities — derivative instruments:						
Commodity contracts	—	43,722	11,076	(35,103)	(c)	19,695
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	—	—	353,261	(d)	353,261
Fixed income securities:						
Cash and cash equivalent funds	—	—	—	795	(e)	795
U.S. Treasury	95,441	—	—	—		95,441
Corporate debt	—	111,623	—	—		111,623
Mortgage-backed securities	—	115,337	—	—		115,337
Municipal bonds	—	80,997	—	—		80,997
Other	—	22,132	—	—		22,132
Subtotal nuclear decommissioning trust	95,441	330,089	—	354,056		779,586
Total	$ 109,962	$ 373,811	$ 11,076	$ 318,953		$ 813,802
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (45,641)	$ (58,482)	$ 31,049	(c)	$ (73,074)

(a) Primarily consists of long-dated electricity contracts.
(b) Represents investments restricted for coal mine reclamation funding related to Four Corners. These assets are included in the Other Assets line item, reported under the Investments and Other Assets section of our Condensed Consolidated Balance Sheets.
(c) Represents counterparty netting, margin, and collateral. See Note 6.
(d) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

(e) Represents nuclear decommissioning trust net pending securities sales and purchases.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 3).

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at September 30, 2017 and December 31, 2016:

	September 30, 2017 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input		Weighted-Average
Commodity Contracts	Assets	Liabilities			Range	
Electricity:						
Forward Contracts (a)	$2,925	$ 19,785	Discounted cash flows	Electricity forward price (per MWh)	$19.87 - $38.13	$ 28.26
Natural Gas:						
Forward Contracts (a)	547	22,292	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.13 - $2.83	$ 2.45
Total	$3,472	$ 42,077				

(a) Includes swaps and physical and financial contracts.

	December 31, 2016 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input		Weighted-Average
Commodity Contracts	Assets	Liabilities			Range	
Electricity:						
Forward Contracts (a)	$10,648	$ 32,042	Discounted cash flows	Electricity forward price (per MWh)	$16.43 - $41.07	$ 29.86
Natural Gas:						

Forward Contracts (a)	428	26,440	Discounted cash flows	Natural gas forward price (per MMBtu)	\$2.32 - \$3.60	\$ 2.81
Total	\$ 11,076	\$ 58,482				

(a) Includes swaps and physical and financial contracts.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts	2017	2016	2017	2016
Net derivative balance at beginning of period	$(36,245)	$(32,380)	$(47,406)	$(32,979)
Total net gains (losses) realized/unrealized:				
Included in OCI	(4)	(10)	(10)	94
Deferred as a regulatory asset or liability	(3,769)	(13,499)	(11,272)	(21,103)
Settlements	1,733	5,424	4,855	11,691
Transfers into Level 3 from Level 2	(5,952)	1,343	(10,340)	1,725
Transfers from Level 3 into Level 2	5,632	(420)	25,568	1,030
Net derivative balance at end of period	$(38,605)	$(39,542)	$(38,605)	$(39,542)
Net unrealized gains included in earnings related to instruments still held at end of period	$—	$—	$—	$—

Amounts included in earnings are recorded in either operating revenues or fuel and purchased power depending on the nature of the underlying contract.

Transfers reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Financial Instruments Not Carried at Fair Value

The carrying value of our net accounts receivable, accounts payable and short-term borrowings approximate fair value. Our short-term borrowings are classified within Level 2 of the fair value hierarchy. See Note 2 for our long-term debt fair values.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

11. Nuclear Decommissioning Trusts

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. APS classifies investments in decommissioning trust funds as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Condensed Consolidated Balance Sheets. See Note 10 for a discussion of how fair value is determined and the classification of the nuclear decommissioning trust investments within the fair value hierarchy. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, we have deferred realized and unrealized gains and losses (including other-than-temporary impairments on investment securities) in other regulatory liabilities. The following table includes the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust fund assets at September 30, 2017 and December 31, 2016 (dollars in thousands):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
September 30, 2017			
Equity securities	$ 401,913	$ 232,727	$ —
Fixed income securities	435,689	12,272	(2,177)
Net receivables (a)	4,378	—	—
Total	$ 841,980	$ 244,999	$ (2,177)

(a) Net receivables/payables relate to pending purchases and sales of securities.

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2016			
Equity securities	$ 353,261	$ 188,091	$ —
Fixed income securities	425,530	9,820	(4,962)
Net receivables (a)	795	—	—
Total	$ 779,586	$ 197,911	$ (4,962)

(a) Net receivables/payables relate to pending purchases and sales of securities.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Realized gains	$598	$4,033	$3,904	$8,753
Realized losses	(1,022)	(3,345)	(4,634)	(6,481)
Proceeds from the sale of securities (a)	76,496	156,825	351,860	447,419

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at September 30, 2017 is as follows (dollars in thousands):

	Fair Value
Less than one year	$ 22,498
1 year – 5 years	103,033
5 years – 10 years	117,044
Greater than 10 years	193,114
Total	$ 435,689

12. New Accounting Standards

Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers

In May 2014, a new revenue recognition accounting standard was issued. This standard provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. Since the issuance of the new revenue standard, additional guidance was issued to clarify certain aspects of the new revenue standard, including principal versus agent considerations, identifying performance obligations, and other narrow scope improvements. The new revenue standard, and related amendments, will be effective for us on January 1, 2018. The standard may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application.

We will adopt this standard on January 1, 2018, and expect to adopt the guidance using the modified retrospective transition approach. We do not expect the adoption of this standard will have significant impacts on our financial statement results; however, adoption of the new standard will impact our disclosures relating to revenue, and may impact our presentation of revenue. Our evaluation is ongoing, but our revenues are derived primarily from sales of electricity to our regulated retail customers, and based on our assessment we do not expect the adoption of this guidance will impact the timing of our revenue recognition relating to these customers.

ASU 2016-01, Financial Instruments: Recognition and Measurement

In January 2016, a new accounting standard was issued relating to the recognition and measurement of financial instruments. The new guidance will require certain investments in equity securities to be measured at

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new standard is effective for us on January 1, 2018. Certain aspects of the standard may require a cumulative effect adjustment and other aspects of the standard are required to be adopted prospectively. We plan on adopting this standard on January 1, 2018, and continue to evaluate the impacts the new guidance may have on our financial statements. As of September 30, 2017 we do not have significant equity investments that would be impacted by this standard.

ASU 2016-02, Leases

In February 2016, a new lease accounting standard was issued. This new standard supersedes the existing lease accounting model, and modifies both lessee and lessor accounting. The new standard will require a lessee to reflect most operating lease arrangements on the balance sheet by recording a right-of-use asset and a lease liability that will initially be measured at the present value of lease payments. Among other changes, the new standard also modifies the definition of a lease, and requires expanded lease disclosures. The new standard will be effective for us on January 1, 2019, with early application permitted. The standard must be adopted using a modified retrospective approach, with various optional practical expedients provided to facilitate transition. We are currently evaluating this new accounting standard and the impacts it will have on our financial statements.

ASU 2016-13, Financial Instruments: Measurement of Credit Losses

In June 2016, a new accounting standard was issued that amends the measurement of credit losses on certain financial instruments. The new standard will require entities to use a current expected credit loss model to measure impairment of certain investments in debt securities, trade accounts receivables, and other financial instruments. The new standard is effective for us on January 1, 2020 and must be adopted using a modified retrospective approach for certain aspects of the standard, and a prospective approach for other aspects of the standard. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

ASU 2017-01, Business Combinations: Clarifying the Definition of a Business

In January 2017, a new accounting standard was issued that clarifies the definition of a business. This standard is intended to assist entities with evaluating whether a transaction should be accounted for as an acquisition (or disposal) of assets or a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. The new standard is effective for us on January 1, 2018 using a prospective approach. At transition we do not expect this standard will have any financial statement impacts; however, the standard may have potential impacts on the accounting for future acquisitions occurring after adoption.

ASU 2017-05, Other Income: Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets

In February 2017, a new accounting standard was issued that intended to clarify the scope of accounting guidance pertaining to gains and losses from the derecognition of nonfinancial assets, and to add guidance for partial sales of nonfinancial assets. The new standard is effective for us on January 1, 2018. The guidance may be applied using either a retrospective or modified retrospective transition approach. Our evaluation is ongoing, but at this time we do not expect the adoption of this guidance, at transition, will have a significant impact on our financial statement results. We are also currently evaluating the transition approach we will apply.

ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, a new accounting standard was issued that modifies how plan sponsors present net periodic pension cost and net periodic postretirement benefit cost (net benefit costs). The presentation changes will require net benefit costs to be disaggregated on the income statement by the various components that comprise these costs. Specifically, only the service cost component will be eligible for presentation as an operating income item, and all other cost components will be presented as non-operating items. This presentation change must be applied retrospectively. Furthermore, the new standard only allows the service cost component to be eligible for capitalization. The change in capitalization requirements must be applied prospectively. The new guidance is effective for us on January 1, 2018. We are currently evaluating this new accounting standard and the impacts it will have on our financial statements. The adoption of this guidance will change our financial statement presentation of net benefit costs and amounts eligible for capitalization; however we do not expect these changes will have a significant impact on our results of operations.

ASU 2017-12, Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities

In August 2017, a new accounting standard was issued that modifies hedge accounting guidance with the intent of simplifying the application of hedge accounting. The new standard is effective for us on January 1, 2019, with early application permitted. At transition the guidance requires the changes to be applied to hedging relationships existing on the date of adoption, with the effect of adoption reflected as of the beginning of the fiscal year of adoption using a cumulative effect adjustment approach. The presentation and disclosure changes may be applied prospectively. We are currently evaluating the new guidance, but at this time we do not expect the adoption of this guidance will have a significant impact on our financial statement results as hedge accounting has been discontinued for the significant majority of our contracts.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

13. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Balance at beginning of period	$(43,626)	$(43,719)	$(43,822)	$(44,748)
Derivative Instruments				
OCI (loss) before reclassifications	9	(29)	(754)	(595)
Amounts reclassified from accumulated other comprehensive loss (a)	710	798	2,480	2,564
Net current period OCI (loss)	719	769	1,726	1,969
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications	—	—	(2,157)	(1,585)
Amounts reclassified from accumulated other comprehensive loss (b)	790	804	2,136	2,218
Net current period OCI (loss)	790	804	(21)	633
Balance at end of period	$(42,117)	$(42,146)	$(42,117)	$(42,146)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 6.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 4.

The following table shows the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three and nine months ended September 30, 2017 and 2016 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Balance at beginning of period	$(25,112)	$(25,928)	$(25,423)	$(27,097)
Derivative Instruments				
OCI (loss) before reclassifications	9	(29)	(754)	(595)
Amounts reclassified from accumulated other comprehensive loss (a)	710	798	2,480	2,564
Net current period OCI (loss)	719	769	1,726	1,969
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications	—	—	(2,121)	(1,521)
Amounts reclassified from accumulated other comprehensive loss (b)	777	799	2,202	2,289
Net current period OCI (loss)	777	799	81	768
Balance at end of period	$(23,616)	$(24,360)	$(23,616)	$(24,360)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 6.

(b) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 4.

14. Asset Retirement Obligations

In the third quarter of 2017, an updated decommissioning study was completed for the Navajo Generating Station, which resulted in an increase to the asset retirement obligation ("ARO") in the amount of $22 million.

The following schedule shows the change in our asset retirement obligations for the nine months ended September 30, 2017 (dollars in thousands):

Asset retirement obligations at January 1, 2017	$624,475
Changes attributable to:	
Accretion expense	24,170
Estimated cash flow revisions	22,211
Asset retirement obligations at September 30, 2017	$670,856

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West’s Condensed Consolidated Financial Statements and APS’s Condensed Consolidated Financial Statements and the related Combined Notes that appear in Item 1 of this report. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see "Forward-Looking Statements" at the front of this report and "Risk Factors" in Part 1, Item 1A of the 2016 Form 10-K and Part II, Item 1A of the 2017 2nd Quarter 10-Q.

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS currently accounts for essentially all of our revenues and earnings.

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. Palo Verde experienced strong performance during the first three quarters of 2017. In April, it completed a refueling outage in 30 days. During the peak summer demand season, its capacity factor was 98.9%.

Coal and Related Environmental Matters and Transactions. APS is a joint owner of three coal-fired power plants and acts as operating agent for two of the plants. APS is focused on the impacts on its coal fleet that may result from increased regulation and potential legislation concerning GHG emissions. On August 3, 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"). (See Note 7 for information regarding challenges to the legality of the Clean Power Plan, a court-ordered stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations, and EPA's proposal to repeal the Clean Power Plan.)

On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan. In its proposal, EPA states that it will issue in the near future an Advanced Notice of Proposed Rulemaking, by which EPA will solicit comments as to potential replacements for the Clean Power Plan that would be consistent with EPA's current legal interpretation of the Clean Air Act. APS will monitor these proceedings to assess whether or how any future proposed regulations of carbon emissions from existing EGUs would affect APS. APS continually analyzes its long-range capital management plans to assess the potential effects of these changes, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to continue participation in such plants.

Cholla

On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required air emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit.

(See Note 3 for details related to the resulting regulatory asset and Note 7 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long-term than the benefits that would have resulted from adding emissions control equipment. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

Four Corners

Asset Purchase Agreement and Coal Supply Matters. On December 30, 2013, APS purchased SCE’s 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS’s prior retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS’s acquisition of SCE’s interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter. The Arizona Court of Appeals reversed an ACC rate decision involving a water company regarding the ACC’s method of finding fair value in that case, which raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision, and on August 8, 2016, the Arizona Supreme Court vacated the Court of Appeals opinion and affirmed the ACC’s orders approving the water company’s SIB adjustor. The Arizona Court of Appeals ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. Supplemental briefing has been completed and the Arizona Court of Appeals heard oral argument on this matter on September 14, 2017. On September 26, 2017, the Court of Appeals affirmed the ACC's decision on the Four Corners rate adjustment.

Concurrently with the closing of the SCE transaction described above, BHP Billiton New Mexico Coal, Inc. ("BHP Billiton"), the parent company of BHP Navajo Coal Company ("BNCC"), the coal supplier and operator of the mine that served Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. Also occurring concurrently with the closing, the Four Corners’ co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016 through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. (See Note 7 for a discussion of a pending arbitration related to the 2016 Coal Supply Agreement.) On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso’s 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC has the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. The parties are currently in discussions as to the future of the option transaction.

The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest. At this time, since NTEC has not yet purchased the 7% interest, the alternate pricing provisions are applicable to 4CA as the holder of the 7% interest. These terms include a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA’s power sales. Such payments are due to 4CA at the end of each calendar year. The balance of this amount at September 30, 2017

is approximately $26 million, $10 million of which is due to 4CA at December 31, 2017. 4CA believes NTEC should satisfy its contractual obligations related to these payments; however, if NTEC fails to meet its contractual obligations when due, 4CA will consider appropriate measures and potential impacts to the Company's financial statements.

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. The environmental group plaintiffs have until November 13, 2017 to file an appeal of this dismissal order with the Ninth Circuit Court of Appeals. We cannot predict whether the plaintiffs will appeal the order or whether such appeal, if filed, will be successful.

Navajo Plant

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease, at which time a new lease will allow for decommissioning activities to begin after December 2019 instead of later this year. The new lease was approved by the Navajo Nation Tribal Council on June 26, 2017. Certain additional approvals are required for specific co-owners, which are expected to occur by late 2017. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the U.S. Department of the Interior have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the Navajo Plant will cease operations in December 2019.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant (see Note 3 for details related to the resulting regulatory asset) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. (See Note 3 for details of the rate recovery in our 2017 retail rate case.)

Transmission and Delivery. APS is working closely with regulators to identify and plan for transmission needs that continue to support system reliability, access to markets and renewable energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section below includes new APS transmission projects through 2019, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better manage their energy usage, minimize system outage durations and frequency, enable customer choice for new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions.

Energy Imbalance Market. In 2015, APS and the California Independent System Operator ("CAISO"), the operator for the majority of California's transmission grid, signed an agreement for APS to begin participation in the Energy Imbalance Market (“EIM”). APS's participation in the EIM began on October 1, 2016. The EIM allows for rebalancing supply and demand in 15-minute blocks with dispatching every five minutes before the energy is needed, instead of the traditional one hour blocks. APS expects that its participation in EIM will lower its fuel costs, improve visibility and situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS’s renewable resources.

Regulatory Matters

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS’s retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. See Note 3 for information on APS’s FERC rates.

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excluded amounts that were then collected on customer bills through adjustor mechanisms. The application requested that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have had an incremental effect on average customer bills. The average annual customer bill impact of APS’s request was an increase of 5.74% (the average annual bill impact for a typical APS residential customer was 7.96%). See Note 3 for details regarding the principal provisions of APS's application.

On March 27, 2017, a majority of the stakeholders in the rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations signed the 2017 Settlement Agreement and filed it with the ACC. The average annual customer bill impact under the 2017 Settlement Agreement is an increase of 3.28% (the average annual bill impact for a typical APS residential customer is 4.54%). (See Note 3 for details of the 2017 Settlement Agreement.)

On August 15, 2017, the ACC approved (by a vote of 4-1), the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS’s general retail rate case, which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017. On August 20, 2017, Commissioner Burns filed a special action petition in the Arizona Supreme

Court seeking to vacate the ACC's order approving the 2017 Settlement

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Agreement so that alleged issues of disqualification and bias on the part of the other Commissioners can be fully investigated. APS opposed the petition, and on October 17, 2017, the Arizona Supreme Court declined to accept jurisdiction over Commissioner Burns' special action petition.

On October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. APS cannot predict the outcome of this appeal but does not believe it will have a material impact.

APS has several recovery mechanisms in place that provide more timely recovery to APS of its fuel and transmission costs, and costs associated with the promotion and implementation of its demand side management and renewable energy efforts and customer programs. These mechanisms are described more fully below and in Note 3.

Renewable Energy. The ACC approved the RES in 2006. The renewable energy requirement is 7% of retail electric sales in 2017 and increases annually until it reaches 15% in 2025. In APS's 2009 retail rate case settlement agreement, APS agreed to exceed the RES standards, committing to use APS's best efforts to obtain 1,700 GWh of new renewable resources to be in service by year-end 2015, in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2016. A component of the RES targets development of distributed energy systems.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which included the revenue neutral transfer of specific revenue requirements in accordance with the 2017 Settlement Agreement. On August 15, 2017, the ACC approved the 2017 RES Implementation Plan.

On June 30, 2017, APS filed its 2018 RES Implementation Plan and proposed a budget of approximately $90 million. APS's budget request supports existing approved projects and commitments and includes the anticipated transfer of specific revenue requirements in accordance with the 2017 Settlement Agreement and also requests a permanent waiver of the residential distributed energy requirement for 2018 contained in the RES rules. APS's 2018 RES budget request is lower than the 2017 RES budget due in part to a certain portion of the RES being collected by APS in base rates rather than through the RES adjustor. The ACC has not yet ruled on APS's 2018 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. The ACC noted that many of the provisions of the original rule may no longer be appropriate, and the underlying economic assumptions associated with the rule have changed dramatically. The proceeding will review such issues as the rapidly declining cost of solar generation, an increased interest in community solar projects, energy storage options, and the decline in fossil fuel generation due to stringent EPA regulations. The proceeding will also examine the feasibility of increasing the standard to 30% of retail sales by 2030, in contrast to the current standard of 15% of retail sales by 2025. APS cannot predict the outcome of this proceeding. See Note 3 for more information on the RES.

The following table summarizes renewable energy sources in APS's renewable portfolio that are in operation and under development as of September 30, 2017.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
Total APS Owned: Solar (a)	239	—
Purchased Power Agreements:		
Solar	310	—
Wind	289	—
Geothermal	10	—
Biomass	14	—
Biogas	6	—
Total Purchased Power Agreements	629	—
Total Distributed Energy: Solar (b)	681	96 (c)
Total Renewable Portfolio	1,549	96

(a) Included in the 239 MW number is 170 MW of solar resources procured through APS's AZ Sun Program.
(b) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in DC and is converted to AC for reporting purposes.
(c) Applications received by APS that are not yet installed and online.

APS has developed and owns solar resources through the ACC-approved AZ Sun Program. APS has invested approximately $675 million in the AZ Sun Program.

Demand Side Management. In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated an Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard of 22% cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. This standard became effective on January 1, 2011.

On June 1, 2016, APS filed its 2017 DSM Implementation Plan, in which APS proposed programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Implementation Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed $4 million Residential Demand Response, Energy Storage and Load Management Program that was filed with the ACC on December 5, 2016 and the requested budget for the 2017 DSM Plan be increased to $66.6 million. On August 15, 2017, the ACC approved the 2017 DSM Plan.

On September 1, 2017, APS filed its 2018 DSM Implementation Plan, which proposes modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Implementation Plan seeks a reduced budget of $52.6 million and requests a waiver of the energy efficiency standard for 2018. See Note 3 for more information on demand side management.

Net Metering. In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, an Administrative Law Judge issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended decision by the Administrative Law Judge. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC’s action, effective as of APS’s 2017 rate case decision, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a resource comparison proxy methodology, a method that is based on the price that APS pays for utility-scale solar projects on a five year rolling average, while a forecasted avoided cost methodology is being developed. The price established by this resource comparison proxy method will be updated annually (between rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior August 19, 2017, the date new rates were effective based on APS's 2017 rate case, will be grandfathered for a period of 20 years from the date the customer’s interconnection application was accepted by the utility;

- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and

- Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh is included in the 2017 Settlement Agreement and became effective on August 19, 2017.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

Subpoena from Arizona Corporation Commissioner Robert Burns. On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, filed subpoenas in APS’s then current retail rate proceeding to APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as

September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Commissioner Burns filed suit against APS and Pinnacle West in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Commissioner Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel. On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself. All defendants have moved to dismiss the complaint. Oral argument at the Superior Court of Arizona for Maricopa County is scheduled for December 19, 2017. APS and Pinnacle West cannot predict the outcome of this matter.

In addition to the Superior Court of Arizona for Maricopa County proceedings discussed above, on August 20, 2017, Commissioner Burns filed a special action petition in the Arizona Supreme Court seeking to vacate the ACC's order approving the settlement so that alleged issues of disqualification and bias on the part of the other Commissioners can be fully investigated. APS opposed the petition, and on October 17, 2017, the Arizona Supreme Court declined to accept jurisdiction over Commissioner Burns' special action petition.

FERC Matter. As part of APS's acquisition of SCE's interest in Four Corners Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed for a rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also

upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS is currently considering next steps and cannot predict whether or if the enforcement division will take any action.

Financial Strength and Flexibility

Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities, and may readily access these facilities ensuring adequate liquidity for each company. Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Other Subsidiaries

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

On March 29, 2016, TransCanyon entered into a strategic alliance agreement with Pacific Gas and Electric Company ("PG&E") to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of California's transmission grid. TransCanyon and PG&E intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

El Dorado. The operations of El Dorado are not expected to have any material impact on our financial results, or to require any material amounts of capital, over the next three years.

4CA. See "Four Corners - Asset Purchase Agreement and Coal Supply Matters" above for information regarding 4CA.

Key Financial Drivers

In addition to the continuing impact of the matters described above, many factors influence our financial results and our future financial outlook, including those listed below. We closely monitor these factors to plan for the Company's current needs, and to adjust our expectations, financial budgets and forecasts appropriately.

Electric Operating Revenues. For the years 2014 through 2016, retail electric revenues comprised approximately 94% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 1.7% for the nine-month period ended September 30, 2017 compared with the prior-year period. For the three years 2014 through 2016, APS's customer growth averaged 1.3% per year. We currently project annual customer growth to be 1.5-2.5% for 2017, 1.5-2.5% for 2018, and to average in the range of 2.0-3.0% for 2017 through 2019 based on our assessment of modestly improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.1% for the nine-month period ended September 30, 2017 compared with the prior-year period. Improving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, distributed renewable generation initiatives and one fewer day of sales due to the leap year in 2016. For the three years 2014 through 2016, APS experienced annual increases in retail electricity sales averaging 0.2%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 0-1.0% for 2017, 0.5-1.5% for 2018, and increase on average in the range of 0.5-1.5% during 2017 through 2019, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Based on past experience, a reasonable range of variation in our kWh sales projections attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to $10 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $10 million.

Fuel and Purchased Power Costs. Fuel and purchased power costs included on our Condensed Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, changes in our generation resource allocation, our hedging program for managing such costs and PSA deferrals and the related amortization.

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, unplanned outages, planned outages (typically scheduled in the spring and fall), renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and changes in depreciation and amortization rates. See "Capital Expenditures" below for information regarding the planned additions to our facilities.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.2% of the assessed

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value for 2016, 11.0% for 2015 and 10.7% for 2014. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units, transmission and distribution facilities.

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities. A specific legislative proposal with respect to broad-based federal tax reform is expected to be released by the House of Representatives in early November. Any such reform may impact the Company's effective tax rate, cash taxes paid and other financial results such as earnings per share, gross revenues and cash flows. Given the number of unknown variables, we are unable to predict any impacts to the Company at this time. In APS's recent retail rate case, the ACC approved a Tax Expense Adjustor Mechanism which may be used to pass through the income tax effects to customers of such broad-based federal tax reform. See Note 3 for details of the Tax Expense Adjustor Mechanism.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 2). The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. An allowance for borrowed funds used during construction offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed in commercial operation.

RESULTS OF OPERATIONS

Pinnacle West's only reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results — Three-month period ended September 30, 2017 compared with three-month period ended September 30, 2016.

Our consolidated net income attributable to common shareholders for the three months ended September 30, 2017 was $276 million, compared with consolidated net income attributable to common shareholders of $263 million for the prior-year period. The results reflect an increase of approximately $13 million for the regulated electricity segment primarily due to higher revenue resulting from the retail regulatory settlement effective August 19, 2017, higher transmission revenues, partially offset by higher depreciation and amortization primarily due to increased plant in service.

The following table presents net income attributable to common shareholders by business segment compared with the prior-year period:

	Three Months Ended September 30, 2017	2016	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$869	$827	$ 42
Operations and maintenance	(222)	(215)	(7)
Depreciation and amortization	(134)	(120)	(14)
Taxes other than income taxes	(45)	(41)	(4)
All other income and expenses, net	7	6	1
Interest charges, net of allowance for borrowed funds used during construction	(50)	(47)	(3)
Income taxes	(144)	(142)	(2)
Less income related to noncontrolling interests (Note 5)	(5)	(5)	—
Net Income Attributable to Common Shareholders	$276	$263	$ 13

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $42 million higher for the three months ended September 30, 2017 compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Impacts of retail regulatory settlement effective August 19, 2017	$24	—	$ 24
Higher transmission revenues (Note 3)	7	—	7
Higher retail sales due to customer growth and higher average effective prices due to customer usage patterns, partially offset by the impacts of efficiency programs and distributed generation	3	—	3
Effects of weather	5	2	3
Higher demand side management regulatory surcharges and renewable energy regulatory surcharges and lower purchased power, partially offset in operations and maintenance costs	1	(1)	2
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(27)	(31)	4
Miscellaneous items, net	(1)	—	(1)
Total	$12	$ (30)	$ 42

Operations and maintenance. Operations and maintenance expenses increased $7 million for the three months ended September 30, 2017 compared with the prior-year period primarily because of:

- An increase of $5 million for employee benefit costs;
- An increase of $3 million related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power; and
- A decrease of $1 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $14 million higher for the three months ended September 30, 2017 compared with the prior-year period primarily related to increased plant in service of $7 million, increased depreciation and amortization rates of $5 million and regulatory deferrals of $2 million.

Income taxes. Income taxes were $2 million higher for the three months ended September 30, 2017 compared with the prior-year period primarily due to the effects of higher pretax income in the current year period, partially offset by a lower effective tax rate in the current period.

Operating Results — Nine-month period ended September 30, 2017 compared with nine-month period ended September 30, 2016.

Our consolidated net income attributable to common shareholders for the nine months ended September 30, 2017 was $467 million, compared with consolidated net income attributable to common shareholders of $389 million for the prior-year period. The results reflect an increase of approximately $75 million for the regulated electricity segment primarily due to higher revenue resulting from the retail regulatory settlement effective August 19, 2017, higher retail sales, higher transmission revenues, and lower operations and maintenance expenses related to fossil generation and Palo Verde costs, partially offset by higher depreciation and amortization primarily due to increased plant in service and increased income taxes.

The following table presents net income attributable to common shareholders by business segment compared with the prior-year period:

	Nine Months Ended September 30, 2017	2016	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$2,012	$1,917	$ 95
Operations and maintenance	(650)	(701)	51
Depreciation and amortization	(386)	(362)	(24)
Taxes other than income taxes	(132)	(126)	(6)
All other income and expenses, net	19	27	(8)
Interest charges, net of allowance for borrowed funds used during construction	(147)	(140)	(7)
Income taxes	(236)	(210)	(26)
Less income related to noncontrolling interests (Note 5)	(15)	(15)	—
Regulated electricity segment income	465	390	75
All other	2	(1)	3
Net Income Attributable to Common Shareholders	$467	$389	$ 78

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $95 million higher for the nine months ended September 30, 2017 compared with the prior-year period. The following table summarizes the major components of this change:

Increase (Decrease)