PINNACLE WEST CAPITAL CORP
Form 10-Q
August 02, 2016

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2016

OR

o 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 x	No o
ARIZONA PUBLIC SERVICE COMPANY	Yes x	No o

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 x No o
ARIZONA PUBLIC SERVICE COMPANY Yes x No o

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

PINNACLE WEST CAPITAL CORPORATION

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

ARIZONA PUBLIC SERVICE COMPANY

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

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 o No x
ARIZONA PUBLIC SERVICE COMPANY Yes o No x

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 July 22, 2016: 111,174,772
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of July 22, 2016: 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" 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, 2015 ("2015 Form 10-K"), 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 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 2015 Form 10-K 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$915,394	$890,648	$1,592,561	$1,561,867
OPERATING EXPENSES				
Fuel and purchased power	274,848	281,477	496,133	504,714
Operations and maintenance	242,279	210,965	485,474	425,909
Depreciation and amortization	123,073	122,739	242,549	243,688
Taxes other than income taxes	42,117	43,032	84,618	86,248
Other expenses	1,329	462	1,877	1,651
Total	683,646	658,675	1,310,651	1,262,210
OPERATING INCOME	231,748	231,973	281,910	299,657
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	10,369	9,345	20,885	18,569
Other income (Note 8)	197	175	314	410
Other expense (Note 8)	(2,842)	(2,609)	(6,880)	(6,895)
Total	7,724	6,911	14,319	12,084
INTEREST EXPENSE				
Interest charges	52,849	48,328	103,593	96,727
Allowance for borrowed funds used during construction	(5,301)	(4,322)	(10,528)	(8,538)
Total	47,548	44,006	93,065	88,189
INCOME BEFORE INCOME TAXES	191,924	194,878	203,164	223,552
INCOME TAXES	65,742	67,371	67,656	75,318
NET INCOME	126,182	127,507	135,508	148,234
Less: Net income attributable to noncontrolling interests (Note 5)	4,874	4,605	9,747	9,210
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$121,308	$122,902	$125,761	$139,024
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,368	110,986	111,336	110,958
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,004	111,460	111,930	111,426
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING				
Net income attributable to common shareholders — basic	$1.09	$1.11	$1.13	$1.25
Net income attributable to common shareholders — diluted	$1.08	$1.10	$1.12	$1.25
DIVIDENDS DECLARED PER SHARE	$1.25	$1.19	$1.25	$1.19

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
NET INCOME	$126,182	$127,507	$135,508	$148,234
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax expense of $80, $16, $626 and $489 for the respective periods	128	25	(566)	(775)
Reclassification of realized loss, net of tax benefit of $392, $556, $191 and $923 for the respective periods	624	874	1,766	2,850
Pension and other postretirement benefits activity, net of tax benefit (expense) of $439, $74, $(206) and $(793) for the respective periods	(701)	(117)	(171)	466
Total other comprehensive income	51	782	1,029	2,541
COMPREHENSIVE INCOME	126,233	128,289	136,537	150,775
Less: Comprehensive income attributable to noncontrolling interests	4,874	4,605	9,747	9,210
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$121,359	$123,684	$126,790	$141,565

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

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

	June 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$43,040	$39,488
Customer and other receivables	278,900	274,691
Accrued unbilled revenues	197,571	96,240
Allowance for doubtful accounts	(2,755)	(3,125)
Materials and supplies (at average cost)	241,612	234,234
Fossil fuel (at average cost)	36,768	45,697
Income tax receivable	—	589
Assets from risk management activities (Note 6)	16,676	15,905
Regulatory assets (Note 3)	108,596	149,555
Other current assets	42,979	37,242
Total current assets	963,387	890,516
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 6)	5,464	12,106
Nuclear decommissioning trust (Note 11)	767,416	735,196
Other assets	54,401	52,518
Total investments and other assets	827,281	799,820
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	16,663,962	16,222,232
Accumulated depreciation and amortization	(5,733,857)	(5,594,094)
Net	10,930,105	10,628,138
Construction work in progress	966,146	816,307
Palo Verde sale leaseback, net of accumulated depreciation (Note 5)	115,450	117,385
Intangible assets, net of accumulated amortization	108,751	123,975
Nuclear fuel, net of accumulated amortization	120,408	123,139
Total property, plant and equipment	12,240,860	11,808,944
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,190,622	1,214,146
Assets for other postretirement benefits (Note 4)	186,505	185,997
Other	129,910	128,835
Total deferred debits	1,507,037	1,528,978
TOTAL ASSETS	$15,538,565	$15,028,258

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

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

	June 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$316,589	$297,480
Accrued taxes	145,167	138,600
Accrued interest	57,927	56,305
Common dividends payable	69,484	69,363
Short-term borrowings (Note 2)	64,140	—
Current maturities of long-term debt (Note 2)	293,580	357,580
Customer deposits	79,136	73,073
Liabilities from risk management activities (Note 6)	55,338	77,716
Liabilities for asset retirements (Note 14)	15,513	28,573
Deferred fuel and purchased power regulatory liability (Note 3)	2,439	9,688
Other regulatory liabilities (Note 3)	113,733	136,078
Other current liabilities	265,498	197,861
Total current liabilities	1,478,544	1,442,317
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 2)	3,897,835	3,462,391
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,794,741	2,723,425
Regulatory liabilities (Note 3)	1,010,821	994,152
Liabilities for asset retirements (Note 14)	446,324	415,003
Liabilities for pension benefits (Note 4)	440,919	480,998
Liabilities from risk management activities (Note 6)	52,212	89,973
Customer advances	101,568	115,609
Coal mine reclamation	203,623	201,984
Deferred investment tax credit	184,998	187,080
Unrecognized tax benefits	9,772	9,524
Other	198,025	186,345
Total deferred credits and other	5,443,003	5,404,093
COMMITMENTS AND CONTINGENCIES (SEE NOTE 7)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,175,500 and 111,095,402 issued at respective dates	2,549,498	2,541,668
Treasury stock at cost; 1,900 and 115,030 shares at respective dates	(130)	(5,806)
Total common stock	2,549,368	2,535,862
Retained earnings	2,079,619	2,092,803
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(37,764)	(37,593)
Derivative instruments	(5,955)	(7,155)
Total accumulated other comprehensive loss	(43,719)	(44,748)
Total shareholders’ equity	4,585,268	4,583,917
Noncontrolling interests (Note 5)	133,915	135,540

Total equity	4,719,183	4,719,457
TOTAL LIABILITIES AND EQUITY	$15,538,565	$15,028,258

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

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

	Six Months Ended June 30, 2016		2015	
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 135,508		$ 148,234	
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization including nuclear fuel	282,291		282,218	
Deferred fuel and purchased power	(21,026	)	11,711	
Deferred fuel and purchased power amortization	13,778		11,424	
Allowance for equity funds used during construction	(20,885	)	(18,569	)
Deferred income taxes	65,881		65,377	
Deferred investment tax credit	(2,083	)	(2,218	)
Change in derivative instruments fair value	(237	)	(225	)
Changes in current assets and liabilities:				
Customer and other receivables	(19,898	)	(17,402	)
Accrued unbilled revenues	(101,331	)	(84,683	)
Materials, supplies and fossil fuel	1,551		(18,311	)
Income tax receivable	589		3,098	
Other current assets	(5,649	)	(8,728	)
Accounts payable	47,621		36,634	
Accrued taxes	6,567		15,199	
Other current liabilities	53,912		(13,138	)
Change in margin and collateral accounts — assets	(34	)	(4,552	)
Change in margin and collateral accounts — liabilities	18,010		26,853	

Change in other long-term assets	(41,101	)	(1,616	)
Change in other long-term liabilities	9,011		(37,012	)
Net cash flow provided by operating activities	422,475		394,294	
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	(731,609	)	(531,035	)
Contributions in aid of construction	29,127		41,010	
Allowance for borrowed funds used during construction	(10,528	)	(8,538	)
Proceeds from nuclear decommissioning trust sales	290,594		225,779	
Investment in nuclear decommissioning trust	(291,734	)	(234,651	)
Other	(1,307	)	(2,068	)
Net cash flow used for investing activities	(715,457	)	(509,503	)
CASH FLOWS FROM FINANCING ACTIVITIES				
Issuance of long-term debt	445,933		600,000	
Repayment of long-term debt	(76,850	)	(344,847	)
Short-term borrowing and payments — net	64,140		10,100	
Dividends paid on common stock	(135,335	)	(128,241	)
Common stock equity issuance - net of purchases	10,017		12,161	
Distributions to noncontrolling interests	(11,372	)	(28,012	)
Other	1		1	
Net cash flow provided by financing activities	296,534		121,162	
NET INCREASE IN CASH AND CASH EQUIVALENTS	3,552		5,953	
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	39,488		7,604	

CASH AND CASH EQUIVALENTS AT END OF PERIOD	$	43,040	$	13,557

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

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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, 2015	110,649,762	$2,512,970	(78,400)	$(3,401)	$1,926,065	$(68,141)	$151,609	$4,519,102
Net income		—		—	139,024	—	9,210	148,234
Other comprehensive income		—		—	—	2,541	—	2,541
Dividends on common stock		—		—	(131,833)	—	—	(131,833)
Issuance of common stock	215,268	13,975		—	—	—	—	13,975
Purchase of treasury stock (a)		—	(93,280)	(6,096)	—	—	—	(6,096)
Reissuance of treasury stock for stock-based compensation and other		—	118,121	7,732	—	—	—	7,732
Capital activities by noncontrolling interests		—		—	—	—	(28,012)	(28,012)
Balance, June 30, 2015	110,865,030	$2,526,945	(53,559)	$(1,765)	$1,933,256	$(65,600)	$132,807	$4,525,643
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		—		—	125,761	—	9,747	135,508
Other comprehensive income		—		—	—	1,029	—	1,029
Dividends on common stock		—		—	(138,947)	—	—	(138,947)
Issuance of common stock	80,098	7,830		—	—	—	—	7,830
Purchase of treasury stock (a)		—	(71,962)	(4,880)	—	—	—	(4,880)
Reissuance of treasury stock for stock-based compensation and		—	185,092	10,556	2	—	—	10,558

other Capital activities by noncontrolling interests	—		—	—		—	(11,372)	(11,372)
Balance, June 30, 2016	111,175,500	$2,549,498	(1,900)	$(130)	$2,079,619	$ (43,719)	$ 133,915	$4,719,183

(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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
ELECTRIC OPERATING REVENUES	$909,757	$889,723	$1,586,389	$1,560,391
OPERATING EXPENSES				
Fuel and purchased power	274,848	281,477	496,133	504,714
Operations and maintenance	233,712	208,031	472,423	417,978
Depreciation and amortization	123,033	122,716	242,479	243,642
Income taxes	70,444	71,672	76,294	83,911
Taxes other than income taxes	42,036	43,123	84,446	86,109
Total	744,073	727,019	1,371,775	1,336,354
OPERATING INCOME	165,684	162,704	214,614	224,037
OTHER INCOME (DEDUCTIONS)				
Income taxes	1,721	2,980	3,536	5,131
Allowance for equity funds used during construction	10,369	9,345	20,885	18,569
Other income (Note 8)	5,747	710	6,357	1,349
Other expense (Note 8)	(4,430)	(2,449)	(9,180)	(7,803)
Total	13,407	10,586	21,598	17,246
INTEREST EXPENSE				
Interest on long-term debt	48,903	44,826	95,722	90,254
Interest on short-term borrowings	1,930	1,705	4,007	2,879
Debt discount, premium and expense	1,195	1,103	2,334	2,237
Allowance for borrowed funds used during construction	(4,999)	(4,311)	(10,039)	(8,527)
Total	47,029	43,323	92,024	86,843
NET INCOME	132,062	129,967	144,188	154,440
Less: Net income attributable to noncontrolling interests (Note 5)	4,874	4,605	9,747	9,210
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$127,188	$125,362	$134,441	$145,230

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
NET INCOME	$132,062	$129,967	$144,188	$154,440
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax expense of $80, $16, $626 and $489 for the respective periods	128	25	(566)	(775)
Reclassification of realized loss, net of tax benefit of $392, $556, $191 and $923 for the respective periods	624	874	1,766	2,850
Pension and other postretirement benefits activity, net of tax benefit (expense) of $403, $47, $(156) and $(722) for the respective periods	(642)	(74)	(31)	607
Total other comprehensive income	110	825	1,169	2,682
COMPREHENSIVE INCOME	132,172	130,792	145,357	157,122
Less: Comprehensive income attributable to noncontrolling interests	4,874	4,605	9,747	9,210
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$127,298	$126,187	$135,610	$147,912

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

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

	June 30, 2016	December 31, 2015
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$16,660,370	$16,218,724
Accumulated depreciation and amortization	(5,730,672)	(5,590,937)
Net	10,929,698	10,627,787
Construction work in progress	948,472	812,845
Palo Verde sale leaseback, net of accumulated depreciation (Note 5)	115,450	117,385
Intangible assets, net of accumulated amortization	108,596	123,820
Nuclear fuel, net of accumulated amortization	120,408	123,139
Total property, plant and equipment	12,222,624	11,804,976
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 11)	767,416	735,196
Assets from risk management activities (Note 6)	5,464	12,106
Other assets	34,843	34,455
Total investments and other assets	807,723	781,757
CURRENT ASSETS		
Cash and cash equivalents	31,207	22,056
Customer and other receivables	278,692	274,428
Accrued unbilled revenues	197,571	96,240
Allowance for doubtful accounts	(2,755)	(3,125)
Materials and supplies (at average cost)	241,612	234,234
Fossil fuel (at average cost)	36,768	45,697
Assets from risk management activities (Note 6)	16,676	15,905
Regulatory assets (Note 3)	108,596	149,555
Other current assets	39,602	35,765
Total current assets	947,969	870,755
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,190,622	1,214,146
Assets for other postretirement benefits (Note 4)	183,131	182,625
Other	128,348	127,923
Total deferred debits	1,502,101	1,524,694
TOTAL ASSETS	$15,480,417	$14,982,182

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)

	June 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$178,162	$178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	2,143,934	2,148,493
Accumulated other comprehensive (loss):		
Pension and other postretirement benefits	(19,973)	(19,942)
Derivative instruments	(5,955)	(7,155)
Total shareholder equity	4,675,864	4,679,254
Noncontrolling interests (Note 5)	133,915	135,540
Total equity	4,809,779	4,814,794
Long-term debt less current maturities (Note 2)	3,772,835	3,337,391
Total capitalization	8,582,614	8,152,185
CURRENT LIABILITIES		
Short-term borrowings (Note 2)	64,140	—
Current maturities of long-term debt (Note 2)	293,580	357,580
Accounts payable	311,655	291,574
Accrued taxes	161,629	144,488
Accrued interest	57,627	56,003
Common dividends payable	69,500	69,400
Customer deposits	79,136	73,073
Liabilities from risk management activities (Note 6)	55,338	77,716
Liabilities for asset retirements (Note 14)	15,513	28,573
Deferred fuel and purchased power regulatory liability (Note 3)	2,439	9,688
Other regulatory liabilities (Note 3)	113,733	136,078
Other current liabilities	239,926	180,535
Total current liabilities	1,464,216	1,424,708
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,830,006	2,764,489
Regulatory liabilities (Note 3)	1,010,821	994,152
Liabilities for asset retirements (Note 14)	446,324	415,003
Liabilities for pension benefits (Note 4)	419,545	459,065
Liabilities from risk management activities (Note 6)	52,212	89,973
Customer advances	101,568	115,609
Coal mine reclamation	203,623	201,984
Deferred investment tax credit	184,998	187,080
Unrecognized tax benefits	35,497	35,251
Other	148,993	142,683
Total deferred credits and other	5,433,587	5,405,289
COMMITMENTS AND CONTINGENCIES (SEE NOTE 7)		
TOTAL LIABILITIES AND EQUITY	$15,480,417	$14,982,182

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)

	Six Months Ended June 30, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 144,188	$ 154,440
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	282,221	282,172
Deferred fuel and purchased power	(21,026)	11,711
Deferred fuel and purchased power amortization	13,778	11,424
Allowance for equity funds used during construction	(20,885)	(18,569)
Deferred income taxes	60,131	24,442
Deferred investment tax credit	(2,083)	(2,218)
Change in derivative instruments fair value	(237)	(225)
Changes in current assets and liabilities:		
Customer and other receivables	(19,809)	(9,250)
Accrued unbilled revenues	(101,331)	(84,683)
Materials, supplies and fossil fuel	1,551	(18,311)
Other current assets	(3,749)	(8,193)
Accounts payable	48,593	37,656
Accrued taxes	17,141	68,382
Other current liabilities	44,711	(31,408)
Change in margin and collateral accounts — assets	(34)	(4,552)
Change in margin and collateral accounts — liabilities	18,010	26,853
	(38,780)	(3,564)

Change in other long-term assets		
Change in other long-term liabilities	3,979	(30,337)
Net cash flow provided by operating activities	426,369	405,770
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(717,729)	(530,850)
Contributions in aid of construction	29,127	41,010
Allowance for borrowed funds used during construction	(10,039)	(8,527)
Proceeds from nuclear decommissioning trust sales	290,594	225,779
Investment in nuclear decommissioning trust	(291,734)	(234,651)
Other	(388)	(614)
Net cash flow used for investing activities	(700,169)	(507,853)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	445,933	600,000
Short-term borrowings and payments — net	64,140	10,100
Repayment of long-term debt	(76,850)	(344,847)
Dividends paid on common stock	(138,900)	(131,700)
Distributions to noncontrolling interests	(11,372)	(28,012)
Net cash flow provided by financing activities	282,951	105,541
NET INCREASE IN CASH AND CASH EQUIVALENTS	9,151	3,458
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	22,056	4,515
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 31,207	$ 7,973
Supplemental disclosure of cash flow information		

Cash paid during the period for:				
Income taxes, net of refunds	$	8,772	$	184
Interest, net of amounts capitalized	$	88,066	$	82,651
Significant non-cash investing and financing activities:				
Accrued capital expenditures	$	55,286	$	38,985
Dividends declared but not yet paid	$	69,500	$	65,900

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, 2015	71,264,947	$178,162	$2,379,696	$1,968,718	$ (48,333)	$ 151,609	$4,629,852
Net income		—	—	145,230	—	9,210	154,440
Other comprehensive income		—	—	—	2,682	—	2,682
Dividends on common stock		—	—	(131,800)	—	—	(131,800)
Other		—	—	2	—	—	2
Net capital activities by noncontrolling interests		—	—	—	—	(28,012)	(28,012)
Balance, June 30, 2015	71,264,947	$178,162	$2,379,696	$1,982,150	$ (45,651)	$ 132,807	$4,627,164
Balance, January 1, 2016	71,264,947	$178,162	$2,379,696	$2,148,493	$ (27,097)	$ 135,540	$4,814,794
Net income		—	—	134,441	—	9,747	144,188
Other comprehensive income		—	—	—	1,169	—	1,169
Dividends on common stock		—	—	(139,000)	—	—	(139,000)
Net capital activities by noncontrolling interests		—	—	—	—	(11,372)	(11,372)
Balance, June 30, 2016	71,264,947	$178,162	$2,379,696	$2,143,934	$ (25,928)	$ 133,915	$4,809,779

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, 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 2015 Form 10-K.

Supplemental Cash Flow Information

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

	Six Months Ended June 30,	
	2016	2015
Cash paid during the period for:		
Income taxes, net of refunds	$2,503	$1,834
Interest, net of amounts capitalized	89,109	84,008
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$55,286	$38,985
Dividends accrued but not yet paid	69,484	65,933

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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West

On May 13, 2016, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2019, with a new $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 June 30, 2016, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

APS

During the first quarter of 2016, APS increased its commercial paper program from $250 million to $500 million.

On April 22, 2016, APS entered into a $100 million term loan facility that matures April 22, 2019. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On May 6, 2016, APS issued $350 million of 3.75% unsecured senior notes that mature on May 15, 2046. The net proceeds from the sale were used to redeem and cancel pollution control bonds (see details below), and to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 13, 2016, APS replaced its $500 million revolving credit facility that would have matured in May 2019, with a new $500 million facility that matures in May 2021.

On June 1, 2016, APS redeemed at par and canceled all $64 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series D and E.

On June 1, 2016, APS redeemed at par and canceled all $13 million of the Coconino County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Navajo Project), 2009 Series A.

On August 1, 2016, APS repaid at maturity APS’s $250 million aggregate principal amount of 6.25% senior notes due August 1, 2016.

At June 30, 2016, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and the $500 million facility that matures in May 2021. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the 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 June 30, 2016, APS had $64 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 separate outstanding letters of credit.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 June 30, 2016		As of December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$125,000	$125,000	$125,000	$125,000
APS	4,066,415	4,658,591	3,694,971	3,981,367
Total	$4,191,415	$4,783,591	$3,819,971	$4,106,367

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 June 30, 2016, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.9 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.6 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 excludes amounts that are currently collected on customer bills through adjustor mechanisms. The application requests 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 an incremental effect on customer bills. The average annual customer bill impact of APS's request is an increase of 5.74% (the average annual bill impact for a typical APS residential customer is 7.96%).

The principal provisions of the application are:

- a test year ended December 31, 2015, adjusted as described below;
- an original cost rate base of $6.8 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits, as of December 31, 2015;

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	44.2 %	5.13 %
Common stock equity	55.8 %	10.50 %
Weighted-average cost of capital		8.13 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;

- a base rate for fuel and purchased power costs of $0.029882 per kilowatt-hour ("kWh") based on estimated 2017 prices (a decrease from the current base fuel rate of $0.03207 per kWh);

- authorization to defer for potential future recovery its share of the construction costs associated with installing selective catalytic reduction equipment at the Four Corners Power Plant (estimated at approximately $400 million in direct costs). APS proposes that the rates established in this rate case be increased through a step mechanism beginning in 2019 to reflect these deferred costs;

- authorization to defer for potential future recovery in the Company's next general rate case the construction costs APS incurs for its Ocotillo power plant modernization project, once the project reaches commercial operation. APS estimates the direct construction costs at approximately $500 million and that the new facility will be fully in service by early 2019;

- authorization to defer until the Company's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;

- updates and modifications to four of APS's adjustor mechanisms - the Power Supply Adjustor ("PSA"), the Lost Fixed Cost Recovery Mechanism ("LFCR"), the Transmission Cost Adjustor ("TCA") and the Environmental Improvement Surcharge ("EIS");

- a number of proposed rate design changes for residential customers, including:
  change the on-peak time of use period from 12 p.m. - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
  reduce the difference in the on- and off-peak energy price and lower all energy charges;
  offer four rate plan options, three of which have demand charges and a fourth that is available to non-partial requirements customers using less than 600 kWh on average per month; and
  modify the current net metering tariff to provide for a credit at the retail rate for the portion of generation by rooftop solar customers that offsets their own load, and for a credit for excess energy delivered to the grid at an export rate.

- proposed rate design changes for commercial customers, including an aggregation rider that allows certain large customers to qualify for a reduced rate, an extra-high load factor rate schedule for certain customers, and an economic development rate offering for new loads meeting certain criteria.

The Company requested that the increase become effective July 1, 2017. On July 22, 2016, the administrative law judge set a procedural schedule for the rate proceedings. The ACC staff and interveners will begin filing their direct testimony on December 21, and the hearing will commence on March 22, 2017. The

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Commission staff supports completing the case within 12 months. APS cannot predict the outcome of its request.

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.

Settlement Agreement

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 kilowatt hour ("kWh"); and (3) the transfer of cost recovery for certain renewable energy projects from the Arizona Renewable Energy Standard and Tariff ("RES") surcharge to base rates in an estimated amount of $36.8 million.

Other key provisions of the 2012 Settlement Agreement include the following:

- An authorized return on common equity of 10.0%;
- A capital structure comprised of 46.1% debt and 53.9% common equity;
- A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;
- Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:
- Deferral of increases in property taxes of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and
- Deferral of 100% in all years if Arizona property tax rates decrease;
- A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of the Four Corners Power Plant ("Four Corners") (APS made its filing under this provision on December 30, 2013, see "Four Corners" below);
- Implementation of a Lost Fixed Cost Recovery ("LFCR") rate mechanism to support energy efficiency and distributed renewable generation;
- Modifications to the Environmental Improvement Surcharge ("EIS") to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;

- Modifications to the Power Supply Adjustor ("PSA"), including the elimination of the 90/10 sharing provision;
- A limitation on the use of the RES surcharge and the Demand Side Management Adjustor Charge ("DSMAC") to recoup capital expenditures not required under the terms of APS's 2009 retail rate case settlement agreement (the "2009 Settlement Agreement");
- Modification of the Transmission Cost Adjustor ("TCA") to streamline the process for future transmission-related rate changes; and
- Implementation of various changes to rate schedules, including the adoption of an experimental "buy-through" rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

The 2012 Settlement Agreement was approved by the ACC on May 15, 2012, with new rates effective on July 1, 2012. This accomplished a goal set by the parties to the 2009 Settlement Agreement to process subsequent rate cases within twelve months of sufficiency findings from the ACC staff, which generally occurs within 30 days after the filing of a rate case.

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 accordance with the ACC's decision on APS's 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 megawatts ("MW") of APS-owned grid scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of grid scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program," is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

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.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a Demand Side Management Implementation Plan ("DSM Plan") for review by and approval of the ACC. In March 2014, the ACC approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

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 approved 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 its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its 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 July 12, 2016, the ACC approved APS's amended DSM Plan and directed APS to spend up to an additional $4 million on a new residential demand response or load management program that facilitates energy storage technology.

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. A formal rulemaking has not been initiated and there has been no additional action on the draft to date. 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 2016 and 2015 (dollars in thousands):

	Six Months Ended June 30,	
	2016	2015
Beginning balance	$(9,688)	$6,925
Deferred fuel and purchased power costs — current period	21,027	(11,710)
Amounts charged to customers	(13,778)	(11,424)
Ending balance	$(2,439)	$(16,209)

The PSA rate for the PSA year beginning February 1, 2016 is $0.001678 per kWh, as compared to $0.000887 per kWh for the prior year. This new rate is comprised of a forward component of $0.001975 per kWh and a historical component of $(0.000297) per kWh. On October 15, 2015, APS notified the ACC that it was initiating a PSA transition component of $(0.004936) per kWh for the months of November 2015, December 2015, and January 2016. The PSA transition component is a mid-year adjustment to the PSA rate that may be established when conditions change sufficiently to cause high balances to accrue in the PSA balancing account. The transition component expired on February 1, 2016. Any uncollected (overcollected) deferrals during the PSA year, after accounting for the transition component, will be included in the calculation of the PSA rate for the PSA year beginning February 1, 2017.

Transmission Rates, Transmission Cost Adjustor 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, 2015, APS’s annual wholesale transmission rates for all users of its transmission system decreased by approximately $17.6 million for the twelve-month period beginning June 1, 2015 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, 2015.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Effective June 1, 2016, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $24.9 million 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.

APS's formula rate protocols have been in effect since 2008. Recent FERC orders suggest that FERC is examining the structure of formula rate protocols and may require companies such as APS to make changes to their protocols in the future.

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 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 files for a LFCR adjustment every January. APS filed its 2014 annual LFCR adjustment on January 15, 2014, requesting a LFCR adjustment of $25.3 million, effective March 1, 2014. The ACC approved APS's LFCR adjustment without change on March 11, 2014, which became effective April 1, 2014. APS filed its 2015 annual LFCR adjustment on January 15, 2015, requesting an LFCR adjustment of $38.5 million, which was approved on March 2, 2015, effective for the first billing cycle of March. 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), to be effective for the first billing cycle of March 2016. In April 2016, the ACC approved the 2016 annual LFCR to be effective in April 2016. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, the one month delay in implementation will not have an adverse effect on APS.

Net Metering

On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 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. APS cannot predict the outcome of this proceeding.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015 and February 23, 2016, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS actively participated in the related hearings held in March 2016. APS has also intervened in the upcoming Tucson Electric Power Company rate case. On June 24, 2016, APS filed testimony in the Tucson Electric Power Company rate case in support of the Tucson Electric Power Company proposed rate design changes. The outcomes of these proceedings will not directly impact our financial position.

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB")

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the “fair value” of a utility’s property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC’s method of finding fair value in that case, and 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 APS filed a brief supporting the ACC’s petition to the Arizona Supreme Court for review of the Court of Appeals’ decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument was conducted on March 22, 2016.   If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS’s ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

System Benefits Charge

The 2012 Settlement Agreement provides 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.

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 $67 million as of June 30, 2016 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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed above, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

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 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. APS cannot predict the outcome of either matter.

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 the United States Environmental Protection Agency ("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. 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 and is seeking recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its current retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($119 million as of June 30, 2016), 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. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, 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.

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Regulatory Assets and Liabilities

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

	Amortization Through	June 30, 2016		December 31, 2015	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$—	$ 617,283	$—	$ 619,223
Retired power plant costs	2033	9,913	122,554	9,913	127,518
Income taxes — allowance for funds used during construction ("AFUDC") equity	2046	5,419	137,611	5,495	133,712
Deferred fuel and purchased power — mark-to-market (Note 6)	2019	30,986	40,573	71,852	69,697
Four Corners cost deferral	2024	6,689	60,238	6,689	63,582
Income taxes — investment tax credit basis adjustment	2045	1,851	47,826	1,766	48,462
Lost fixed cost recovery (b)	2017	49,852	—	45,507	—
Palo Verde VIEs (Note 5)	2046	—	18,465	—	18,143
Deferred compensation	2036	—	35,701	—	34,751
Deferred property taxes	(c)	—	62,726	—	50,453
Loss on reacquired debt	2034	1,592	16,919	1,515	16,375
Tax expense of Medicare subsidy	2024	1,512	11,647	1,520	12,163
Transmission vegetation management	2016	—	—	4,543	—
Mead-Phoenix transmission line CIAC	2050	332	10,874	332	11,040
Transmission cost adjustor (b)	2018	—	2,814	—	2,942
Coal reclamation	2026	418	5,391	418	6,085
Other	Various	32	—	5	—
Total regulatory assets (d)		$ 108,596	$ 1,190,622	$ 149,555	$ 1,214,146

(a) This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to Other Comprehensive Income ("OCI") and result in lower future revenues. See Note 4 for further discussion.

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

(c) Per the provision of the 2012 Settlement Agreement.

(d) 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."

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Amortization Through	June 30, 2016		December 31, 2015	
		Current	Non-Current	Current	Non-Current
Asset retirement obligations	2057	$—	$ 299,713	$—	$ 277,554
Removal costs	(a)	26,373	245,777	39,746	240,367
Other postretirement benefits	(d)	33,294	155,279	34,100	179,521
Income taxes — deferred investment tax credit	2045	3,774	95,877	3,604	97,175
Income taxes — change in rates	2046	1,771	71,257	1,113	72,454
Spent nuclear fuel	2047	31	71,342	3,051	67,437
Renewable energy standard (b)	2017	35,882	2,182	43,773	4,365
Demand side management (b)	2017	4,957	21,864	6,079	19,115
Sundance maintenance	2030	—	14,483	—	13,678
Deferred fuel and purchased power (b) (c)	2017	2,439	—	9,688	—
Deferred gains on utility property	2019	2,062	9,535	2,062	6,001
Transmission cost adjustor (b)	2017	5,545	—	—	—
Four Corners coal reclamation	2031	—	15,969	—	8,920
Other	Various	44	7,543	2,550	7,565
Total regulatory liabilities		$ 116,172	$ 1,010,821	$ 145,766	$ 994,152

(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 "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) See Note 4.

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. On September 30, 2014, Pinnacle West announced plan design changes to the other postretirement benefit plan. Because of the plan changes, the Company is currently in the process of seeking Internal Revenue Service ("IRS") and regulatory approval to move approximately $140 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs.

Certain pension and other postretirement benefit costs in excess of amounts recovered in electric retail rates were deferred in 2011 and 2012 as a regulatory asset for future recovery, pursuant to APS's 2009 retail rate case settlement. Pursuant to this order, we began amortizing the regulatory asset over three years beginning in July 2012. We completed amortizing these costs as of June 30, 2015. We amortized approximately $2 million and $4 million for the three and six months ended June 30, 2015, respectively.

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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, billed to electric plant participants or charged or amortized to the regulatory asset) (dollars in thousands):

	Pension Benefits				Other Benefits			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015	2016	2015	2016	2015
Service cost — benefits earned during the period	$12,630	$13,990	$26,896	$29,814	$3,560	$4,068	$7,497	$8,413
Interest cost on benefit obligation	32,878	30,802	65,823	61,992	7,519	6,867	14,860	14,051
Expected return on plan assets	(43,161)	(44,467)	(86,953)	(89,616)	(9,125)	(9,281)	(18,247)	(18,428)
Amortization of:								
Prior service cost	132	149	263	297	(9,471)	(9,492)	(18,942)	(18,984)
Net actuarial loss	10,627	7,767	20,358	15,528	1,349	880	2,295	2,441
Net periodic benefit cost	$13,106	$8,241	$26,387	$18,015	$(6,168)	$(6,958)	$(12,537)	$(12,507)
Portion of cost charged to expense	$6,433	$5,232	$12,951	$11,219	$(3,027)	$(2,482)	$(6,153)	$(4,271)

Contributions

We made voluntary contributions of $80 million to our pension plan year-to-date in 2016. 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 2016-2018 period. We expect to make contributions of approximately $1 million in each of 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 for the period 2016 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, resulting in an increase in net income for the three and six months ended June 30, 2016 of $5 million and $10 million respectively, and for the three and six months ended June 30, 2015 of $5 million and $9 million

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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 June 30, 2016 and December 31, 2015 include the following amounts relating to the VIEs (in thousands):

	June 30, 2016	December 31, 2015
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$115,450	$117,385
Equity — Noncontrolling interests	133,915	135,540

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 United States 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 $288 million beginning in 2016, 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

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with market volatility 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. We also enter into derivative instruments for economic hedging purposes. While we believe the economic hedges 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. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

Hedge effectiveness is the degree to which the derivative instrument contract and the hedged item are correlated and is measured based on the relative changes in fair value of the derivative instrument contract and the hedged item over time. We assess hedge effectiveness both at inception and on a continuing basis. These assessments exclude the time value of certain options. For accounting hedges that are deemed an effective hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of OCI and reclassified into earnings in the same period during which the hedged transaction affects earnings. We recognize in current earnings, subject to the PSA, the gains and losses representing hedge ineffectiveness, and the gains and losses on any hedge components which are excluded from our effectiveness assessment. As cash flow hedge accounting has been discontinued for the significant majority of our contracts, after May 31, 2012, effectiveness testing is no longer being performed for these contracts.

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

Commodity	Quantity	
Power	2,291	GWh
Gas	220	Billion cubic feet

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 six months ended June 30, 2016 and 2015 (dollars in thousands):

	Financial Statement Location	Three Months Ended June 30,		Six Months Ended June 30,	
Commodity Contracts		2016	2015	2016	2015
Gain (loss) recognized in OCI on derivative instruments (effective portion)	OCI — derivative instruments	$208	$41	$60	$(286)
Loss reclassified from accumulated OCI into income (effective portion realized) (a)	Fuel and purchased power (b)	(1,016)	(1,430)	(1,957)	(3,773)

(a) During the three and six months ended June 30, 2016 and 2015, 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.

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During the next twelve months, we estimate that a net loss of $4 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.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the three and six months ended June 30, 2016 and 2015 (dollars in thousands):

	Financial Statement Location	Three Months Ended June 30,		Six Months Ended June 30,	
Commodity Contracts		2016	2015	2016	2015
Net gain (loss) recognized in income	Operating revenues	$585	$(66)	$483	$(114)
Net gain (loss) recognized in income	Fuel and purchased power (a)	60,894	10,613	29,958	(34,190)
Total		$61,479	$10,547	$30,441	$(34,304)

(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 June 30, 2016 and December 31, 2015, include gross liabilities of $2 million and $3 million, respectively, of derivative instruments designated as hedging instruments.

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 June 30, 2016 and December 31, 2015. 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.

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As of June 30, 2016: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 30,393	$ (14,424)	$ 15,969	$ 707	$ 16,676
Investments and other assets	14,260	(8,796)	5,464	—	5,464
Total assets	44,653	(23,220)	21,433	707	22,140
Current liabilities	(65,432)	14,424	(51,008)	(4,330)	(55,338)
Deferred credits and other	(61,008)	8,796	(52,212)	—	(52,212)
Total liabilities	(126,440)	23,220	(103,220)	(4,330)	(107,550)
Total	$ (81,787)	$ —	$ (81,787)	$ (3,623)	$ (85,410)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $0.
(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 $4,330, and cash margin provided to counterparties of $707.

As of December 31, 2015: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 37,396	$ (22,163)	$ 15,233	$ 672	$ 15,905
Investments and other assets	15,960	(3,854)	12,106	—	12,106
Total assets	53,356	(26,017)	27,339	672	28,011
Current liabilities	(113,560)	40,223	(73,337)	(4,379)	(77,716)
Deferred credits and other	(93,827)	3,854	(89,973)	—	(89,973)
Total liabilities	(207,387)	44,077	(163,310)	(4,379)	(167,689)
Total	$ (154,031)	$ 18,060	$ (135,971)	$ (3,707)	$ (139,678)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $18,060.
(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 $4,379, and cash margin provided to counterparties of $672.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management contracts with many counterparties, including one counterparty for which our exposure represents approximately 73% of Pinnacle West's $22 million of risk management assets as of June 30, 2016. This exposure relates to a long-term traditional wholesale contract with a counterparty that has a high credit quality. 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

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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).

The following table provides information about our derivative instruments that have credit-risk-related contingent features at June 30, 2016 (dollars in thousands):

	June 30, 2016
Aggregate fair value of derivative instruments in a net liability position	$126,440
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	76,949

(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 $145 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 provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016.

APS has submitted two claims pursuant to the terms of the August 18, 2014 settlement agreement, for two separate time periods during July 1, 2011 through June 30, 2015. The DOE has approved and paid $53.9 million for these claims (APS's share is $15.7 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. 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 2016, and payment is expected in the second quarter of 2017.

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 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 $13.4 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of $13 billion of liability coverage is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum retrospective premium assessment per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to an annual limit of $18.9 million per incident, to be periodically adjusted for inflation. Based on APS's ownership interest in the three Palo Verde units, APS's maximum potential retrospective premium assessment per incident for all three units is approximately $111.1 million, with a maximum annual retrospective premium assessment of approximately $16.6 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of replacement generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium assessments 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 $23.8 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 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

There have been no material changes, as of June 30, 2016, outside the normal course of business in contractual obligations from the information provided in our 2015 Form 10-K. See Note 2 for discussion regarding changes in our long-term debt obligations.

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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 work plan. 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. 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.

Southwest Power Outage

On September 8, 2011 at approximately 3:30 PM, a 500 kilovolt ("kV") transmission line running between the Hassayampa and North Gila substations in southwestern Arizona tripped out of service due to a fault that occurred at a switchyard operated by APS. Approximately ten minutes after the transmission line went off-line, generation and transmission resources for the Yuma area were lost, resulting in approximately 69,700 APS customers losing service.

On September 6, 2013, a purported consumer class action complaint was filed in Federal District Court in San Diego, California, naming APS and Pinnacle West as defendants and seeking damages for loss of perishable inventory and sales as a result of interruption of electrical service. APS and Pinnacle West filed a motion to dismiss, which the court granted on December 9, 2013. On January 13, 2014, the plaintiffs appealed the lower court’s decision. On March 2, 2016, the United States Court of Appeals for the Ninth Circuit unanimously affirmed the District Court's decision. The plaintiffs filed a Petition for Rehearing En Banc, which was denied on April 11, 2016.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time,

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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 requirements on Four Corners and the Navajo Generating Station ("Navajo Plant"). EPA and ADEQ 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 is currently in the process of considering a proposed rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility.

Four Corners. Based on EPA’s final standards, APS estimates that its 63% share of the cost of these 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. 4C Acquisition, LLC ("4CA"), a wholly-owned subsidiary of Pinnacle West, 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 provided notice of its intent to exercise the option. 4CA is negotiating a definitive purchase agreement with NTEC for the purchase by NTEC of the 7% interest. 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. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process.

Cholla. APS believes that EPA’s final rule as it applies to Cholla, which would require installation of selective catalytic reduction ("SCR") controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona’s State Implementation Plan ("SIP") and promulgating a FIP that is inconsistent with the state’s considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, 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. APS’s proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015.

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On October 16, 2015, ADEQ issued the Cholla permit, 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. The proposed rule was published in the Federal Register on July 19, 2016 and is subject to a 45-day public comment period. APS anticipates that EPA will issue the final rule by the end of 2016. Once EPA’s action is finalized, there may be judicial petitions for review of EPA’s final action filed in the Ninth Circuit Court of Appeals. APS cannot predict at this time whether such petitions will be filed or if they will be successful.

Mercury and Air Toxic Standards ("MATS"). In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excludes costs related to Cholla Unit 2, which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. Salt River Project Agricultural Improvement and Power District ("SRP"), the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. Litigation concerning the rules has occurred and further litigation concerning the propriety of EPA's related findings is expected. These proceedings do not materially impact APS. Regardless of the results from further judicial or administrative proceedings concerning the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

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.

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule’s requirements. 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.

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 $15 million, and its share of incremental costs for Cholla is approximately $40 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 on-going groundwater monitoring. Depending upon the results of such monitoring at each of Cholla, Four Corners and the Navajo Plant, we may be required to take corrective actions. Because the initial monitoring at these plants is not yet complete, at the present time expenditures related to potential corrective actions cannot be reasonably estimated.

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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 three 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, though, APS cannot predict when EPA will commence its rulemaking concerning boron or the eventual results of those proceedings.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for existing, new, modified, and reconstructed electric generating units ("EGUs"). EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA's recently finalized "Clean Power Plan" imposes state-specific goals or targets to achieve reductions in CO_2 emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA's final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state's goal is an emissions performance standard that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to states establishing a need for additional time; however, it is expected that this timing will be impacted by the court-imposed stay described below.

Prior to the court-imposed stay described below, ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, was working to develop a compliance plan for submittal to EPA. Since the imposition of the stay, ADEQ reports that it is continuing to assess its options while completing outreach and soliciting feedback from stakeholders. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. 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. We cannot predict the extent of such a delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output or potential plant closures, as alternatives to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains on-going, and additional information or considerations may arise that change our expectations.

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.

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Federal Agency Environmental Lawsuit Related to Four Corners

On December 21, 2015, several environmental groups filed a notice of intent to sue with Office of Surface Mining Reclamation and Enforcement ("OSM") and other federal agencies under the Endangered Species Act (“ESA”) alleging that OSM’s reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the United States Department of the Interior's ("DOI's") review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. This review process also required separate environmental impact evaluations under the National Environmental Policy Act (“NEPA”) and culminated in the issuance of a Record of Decision justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, the same environmental groups followed through with their notice of intent to sue by filing a lawsuit against OSM and other DOI 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. Expanding upon the December 2015 ESA notice, 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. We filed a motion to intervene in the proceedings on July 15, 2016. We cannot predict the outcome of this matter or its potential effect on Four Corners.

New Mexico Tax Matter

On May 23, 2013, the New Mexico Taxation and Revenue Department ("NMTRD") issued a notice of assessment for coal severance surtax, penalty, and interest totaling approximately $30 million related to coal supplied under the coal supply agreement for Four Corners (the "Assessment"). APS’s share of the Assessment is approximately $12 million. For procedural reasons, on behalf of the Four Corners co-owners, including APS, the coal supplier made a partial payment of the Assessment in the amount of $0.8 million and immediately filed a refund claim with respect to that partial payment in August 2013. The NMTRD denied the refund claim. On December 19, 2013, the coal supplier and APS, on its own behalf and as operating agent for Four Corners, filed a complaint with the New Mexico District Court contesting both the validity of the Assessment and the refund claim denial. On June 30, 2015, the court ruled that the Assessment was not valid and further ruled that APS and the other Four Corners co-owners receive a refund of all of the contested amounts previously paid under the applicable tax statute. The NMTRD filed an appeal of the decision on August 31, 2015.

On March 16, 2016, APS and the coal supplier entered into a final settlement agreement with the NMTRD with respect to the Assessment. Pursuant to the final settlement agreement, the NMTRD agreed to release the Assessment, dismiss its filed appeal, and release its rights to any other surtax claims with respect to the coal supply agreement. APS and the other Four Corners co-owners agreed to forgo refund rights with respect to all of the contested amounts previously paid under the applicable tax statute, as well as pay $1 million. APS's share of this settlement payment, together with its share of the partial payment described above is approximately $0.8 million.

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 June 30,

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2016, standby letters of credit totaled $79 million and will expire in 2016 and 2017. As of June 30, 2016, surety bonds expiring through 2019 totaled $150 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 June 30, 2016. Effective July 6, 2016, Pinnacle West has issued two 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.

Peabody Bankruptcy

On April 13, 2016, Peabody Energy Corporation and certain affiliated entities filed a petition for relief under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Missouri. Under a Coal Supply Agreement, dated December 21, 2005, Peabody supplied coal to APS and PacifiCorp (collectively, the "Buyers") for use at the Cholla power plant in Arizona. APS believes that the Coal Supply Agreement terminated automatically on April 13, 2016 as a result of Peabody's bankruptcy filing. The Buyers filed a motion requesting that the Bankruptcy Court enter an order determining that the Buyers are authorized to enforce the termination provisions in the Coal Supply Agreement.

On May 13, 2016, Peabody filed a complaint against the Buyers in the bankruptcy court in which Peabody alleges that the Buyers have breached the Agreement. Peabody requests substantial, but unspecified, monetary damages from the Buyers. Peabody and the Buyers have agreed to commence non-binding mediation, failing which a trial is expected to occur in November 2016. There is insufficient information at this time to reasonably estimate any possible loss or range of loss to the Company.

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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 six months ended June 30, 2016 and 2015 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Other income:				
Interest income	$184	$184	$302	$294
Investment gains — net	13	—	13	—
Miscellaneous	—	(9)	(1)	116
Total other income	$197	$175	$314	$410
Other expense:				
Non-operating costs	$(2,085)	$(1,952)	$(4,133)	$(4,200)
Investment losses — net	(539)	(650)	(1,058)	(1,145)
Miscellaneous	(218)	(7)	(1,689)	(1,550)
Total other expense	$(2,842)	$(2,609)	$(6,880)	$(6,895)

The following table provides detail of APS's other income and other expense for the three and six months ended June 30, 2016 and 2015 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Other income:				
Interest income	$109	$6	$181	$73
Gain on disposition of property	4,989	478	5,321	685
Miscellaneous	649	226	855	591
Total other income	$5,747	$710	$6,357	$1,349
Other expense:				
Non-operating costs (a)	$(2,719)	$(1,878)	$(4,685)	$(4,395)
Loss on disposition of property	(657)	(251)	(1,083)	(894)
Miscellaneous	(1,054)	(320)	(3,412)	(2,514)
Total other expense	$(4,430)	$(2,449)	$(9,180)	$(7,803)

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

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9. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for the three and six months ended June 30, 2016 and 2015 (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income attributable to common shareholders	$121,308	$122,902	$125,761	$139,024
Weighted average common shares outstanding — basic	111,368	110,986	111,336	110,958
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	636	474	594	468
Weighted average common shares outstanding — diluted	112,004	111,460	111,930	111,426
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$1.09	$1.11	$1.13	$1.25
Net income attributable to common shareholders — diluted	$1.08	$1.10	$1.12	$1.25

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

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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 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. During the first quarter of 2016 we retrospectively adopted new accounting guidance that requires instruments valued using NAV, as a practical expedient, to no longer be classified within the fair value hierarchy. As such, instruments valued using NAV, as a practical expedient, are included in our fair value disclosures and tables in a separate column; however, these investments are not classified within any of the fair value hierarchy levels. Prior to the adoption of this guidance these instruments were typically reported within Level 2 or Level 3. The adoption of this guidance changes our fair value disclosures, but does not impact the methodology for valuing these instruments, or our financial statement results.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust and plan assets held in our retirement and other benefit plans. See Note 7 in the 2015 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.

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.

Option contracts are primarily valued using a Black-Scholes option valuation model, which utilizes both observable and unobservable inputs such as broker quotes, interest rates and price volatilities.

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 and the use of option valuation models with significant unobservable inputs.

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 June 30, 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 June 30, 2016
Assets						
Cash equivalents	$ 9,857	$—	$ —	$—		$9,857
Risk management activities — derivative instruments:						
Commodity contracts	—	26,509	18,118	(22,487)	(b)	22,140
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	—	—	328,037	(c)	328,037
Fixed income securities:						
Cash and cash equivalent funds	17,892	—	—	(13,139)	(d)	4,753
U.S. Treasury	117,448	—	—	—		117,448
Corporate debt	—	106,399	—	—		106,399
Mortgage-backed securities	—	112,771	—	—		112,771
Municipal bonds	—	73,847	—	—		73,847
Other	—	24,161	—	—		24,161
Subtotal nuclear decommissioning trust	135,340	317,178	—	314,898		767,416
Total	$ 145,197	$343,687	$ 18,118	$292,411		$799,413
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(75,916)	$ (50,498)	$18,864	(b)	$(107,550)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 6.
(c) Valued using NAV as a practical expedient, and therefore not classified in the fair value hierarchy.
(d) Represents nuclear decommissioning trust net pending securities sales and purchases.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2015, 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, 2015
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$22,992	$ 30,364	$(25,345)	(b)	$28,011
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	—	—	314,957	(c)	314,957
Fixed income securities:						
Cash and cash equivalent funds	12,260	—	—	(335)	(d)	11,925
U.S. Treasury	117,245	—	—	—		117,245
Corporate debt	—	96,243	—	—		96,243
Mortgage-backed securities	—	99,065	—	—		99,065
Municipal bonds	—	72,206	—	—		72,206
Other	—	23,555	—	—		23,555
Subtotal nuclear decommissioning trust	129,505	291,069	—	314,622		735,196
Total	$ 129,505	$314,061	$ 30,364	$289,277		$763,207
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(144,044)	$ (63,343)	$39,698	(b)	$(167,689)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 6.
(c) Valued using NAV as a practical expedient, and therefore not classified in the fair value hierarchy.
(d) Represents nuclear decommissioning trust net pending securities sales and purchases.

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 and option model inputs. 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Our option contracts classified as Level 3 primarily relate to purchase heat rate options. The significant unobservable inputs at June 30, 2016 and December 31, 2015 for these instruments include electricity prices, and volatilities. If electricity prices and electricity price volatilities increase, we would expect the fair value of these options to increase, and if these valuation inputs decrease, we would expect the fair value of these options to decrease. If natural gas prices and natural gas price volatilities increase, we would expect the fair value of these options to decrease, and if these inputs decrease, we would expect the fair value of the options to increase. The commodity prices and volatilities do not always move in corresponding directions. The options' fair values are impacted by the net changes of these various inputs.

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 June 30, 2016 and December 31, 2015:

	June 30, 2016 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input		Weighted-Average	
Commodity Contracts	Assets	Liabilities			Range		
Electricity:							
Forward Contracts (a)	$16,151	$39,548	Discounted cash flows	Electricity forward price (per MWh)	$21.68 - $43.50	$ 31.26	
Option Contracts (b)	—	2,993	Option model	Electricity forward price (per MWh)	$35.46 - $49.65	$ 43.12	
				Electricity price volatilities	56% - 140%	94	%
				Natural gas price volatilities	38% - 80%	49	%
Natural Gas:							
Forward Contracts (a)	1,967	7,957	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.67 - $3.37	$ 2.91	
Total	$18,118	$50,498					

(a) Includes swaps and physical and financial contracts.

(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

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Commodity Contracts	December 31, 2015 Fair Value (thousands) Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average	
Electricity:							
Forward Contracts (a)	$24,543	$54,679	Discounted cash flows	Electricity forward price (per MWh)	$15.92 - $40.73	$ 26.86	
Option Contracts (b)	—	5,628	Option model	Electricity forward price (per MWh)	$23.87 - $44.13	$ 33.91	
				Electricity price volatilities	40% - 59%	52	%
				Natural gas price volatilities	32% - 40%	35	%
Natural Gas:							
Forward Contracts (a)	5,821	3,036	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.18 - $3.14	$ 2.61	
Total	$30,364	$63,343					

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

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 six months ended June 30, 2016 and 2015 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Commodity Contracts	2016	2015	2016	2015
Net derivative balance at beginning of period	$(39,507)	$(48,814)	$(32,979)	$(41,386)
Total net gains (losses) realized/unrealized:				
Included in OCI	104	25	104	(237)
Deferred as a regulatory asset or liability	1,499	5,813	(7,604)	(4,933)
Settlements	4,502	4,541	6,267	4,852
Transfers into Level 3 from Level 2	120	(3,566)	382	(3,968)
Transfers from Level 3 into Level 2	902	(944)	1,450	2,727
Net derivative balance at end of period	$(32,380)	$(42,945)	$(32,380)	$(42,945)
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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

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 June 30, 2016 and December 31, 2015 (dollars in thousands):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
June 30, 2016			
Equity securities	$328,037	$ 165,926	$ (7)
Fixed income securities	452,518	22,953	(345)
Net payables (a)	(13,139)	—	—
Total	$767,416	$ 188,879	$ (352)

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2015			
Equity securities	$314,957	$ 157,098	$ (115)
Fixed income securities	420,574	11,955	(2,645)
Net payables (a)	(335)	—	—
Total	$735,196	$ 169,053	$ (2,760)

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

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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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Realized gains	$2,282	$1,260	$4,720	$2,455
Realized losses	(1,350)	(1,525)	(3,136)	(2,050)
Proceeds from the sale of securities (a)	148,785	110,498	290,594	225,779

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at June 30, 2016 is as follows (dollars in thousands):

	Fair Value
Less than one year	$ 13,046
1 year – 5 years	133,548
5 years – 10 years	103,874
Greater than 10 years	202,050
Total	$ 452,518

12. New Accounting Standards

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 has been 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 guidance 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 are currently evaluating the new standard, and related amendments, and the impacts it may have on our financial statements.

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 fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new guidance is effective for us on January 1, 2018. Certain aspects of the guidance may require a cumulative-effect adjustment and other aspects of the guidance are required to be adopted prospectively. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

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 guidance 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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

new standard will be effective for us on January 1, 2019, with early application permitted. The guidance 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 may have on our financial statements.

In March 2016, new stock compensation accounting guidance was issued that modifies the accounting for employee share-based payments. The new guidance will require all tax benefits and deficiencies arising from share-based payments to be recognized in net income, modifies the tax withholding threshold for awards to qualify for equity classification, simplifies accounting for forfeitures, and clarifies certain cash flow presentation matters. The new guidance is effective for us on January 1, 2017, with early application permitted. Certain aspects of the guidance must be adopted using a prospective approach and other aspects will be adopted using a retrospective approach. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

In June 2016, new accounting guidance was issued that amends the measurement of credit losses on certain financial instruments. The new guidance 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.

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 six months ended June 30, 2016 and 2015 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Balance at beginning of period	$(43,770)	$(66,382)	$(44,748)	$(68,141)
Derivative Instruments				
OCI (loss) before reclassifications	128	25	(566)	(775)
Amounts reclassified from accumulated other comprehensive loss (a)	624	874	1,766	2,850
Net current period OCI (loss)	752	899	1,200	2,075
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications	(1,585)	(969)	(1,585)	(969)
Amounts reclassified from accumulated other comprehensive loss (b)	884	852	1,414	1,435
Net current period OCI (loss)	(701)	(117)	(171)	466
Balance at end of period	$(43,719)	$(65,600)	$(43,719)	$(65,600)

(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.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 six months ended June 30, 2016 and 2015 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Balance at beginning of period	$(26,038)	$(46,476)	$(27,097)	$(48,333)
Derivative Instruments				
OCI (loss) before reclassifications	128	25	(566)	(775)
Amounts reclassified from accumulated other comprehensive loss (a)	624	874	1,766	2,850
Net current period OCI (loss)	752	899	1,200	2,075
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications	(1,521)	(927)	(1,521)	(927)
Amounts reclassified from accumulated other comprehensive loss (b)	879	853	1,490	1,534
Net current period OCI (loss)	(642)	(74)	(31)	607
Balance at end of period	$(25,928)	$(45,651)	$(25,928)	$(45,651)

(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 2016, APS recognized an asset retirement obligation (“ARO”) for the Ocotillo steam units as a condition of the air permit (issued in 2016) to allow the construction and operation of five new turbine units. This resulted in an increase to the ARO in the amount of $10 million.

The following schedule shows the change in our asset retirement obligations for the six months ended June 30, 2016 (dollars in thousands):

Asset retirement obligations at January 1, 2016	$443,576
Changes attributable to:	
Accretion expense	13,112
Settlements	(5,224)
Newly incurred liabilities	10,373
Asset retirement obligations at June 30, 2016	$461,837

Decommissioning activities for Four Corners Units 1-3 began in January 2014. Decommissioning activities for Cholla Ash Ponds began in January 2015. Thus, $16 million of the total asset retirement obligation of $462 million at June 30, 2016, is classified as a current liability on the balance sheet.

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 2015 Form 10-K.

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. The March 2011 earthquake and tsunamis in Japan and the resulting accident at Japan's Fukushima Daiichi nuclear power station had a significant impact on nuclear power operators worldwide. In the aftermath of the accident, the NRC conducted an independent assessment to consider actions to address lessons learned from the Fukushima events. The independent assessment, named the "Near Term Task Force," recommended a number of proposed enhancements to U.S. commercial nuclear power plant equipment and emergency plans. The NRC has directed nuclear power plants to begin implementing some of the Near Term Task Force's recommendations. Palo Verde has met the NRC's imposed deadlines for installation of equipment to address these requirements, and has minor additional work to perform in 2016. To implement these recommendations, Palo Verde has spent approximately $125 million on capital enhancements as of June 30, 2016 (APS's share is 29.1%).

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 June 2, 2014, EPA proposed a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), and EPA finalized its proposal on August 3, 2015.

EPA's nationwide CO_2 emissions reduction goal is 32% below 2005 emission levels. As finalized for the state of Arizona and the Navajo Nation, compliance with the Clean Power Plan could involve a shift in generation from coal to natural gas and renewable generation. Until implementation plans for these jurisdictions are finalized, we are unable to determine the actual impacts to 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 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. (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.

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 has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed below, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction, 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 serves 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. BHP Billiton will be retained by NTEC under contract as the mine manager and operator through 2016. 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, when the current coal supply agreement expires, 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. 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. The cash purchase price is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. 4CA, a wholly-owned subsidiary of Pinnacle West, purchased the El Paso interest on July 6, 2016.
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. 4CA is negotiating a definitive purchase agreement with NTEC for the purchase by NTEC of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

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 DOI 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. We filed a motion to intervene in the proceedings on July 15, 2016. We cannot predict the outcome of this matter or its potential effect on Four Corners.

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 proposed rate recovery in our current retail rate case filing.) APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor's report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process, including any EPA Environmental Appeals Board ("EAB") reviews, before construction can begin. On April 21, 2016, the Sierra Club filed a petition with the EAB to review the Prevention of Significant Deterioration permit issued by Maricopa County, Arizona for the Ocotillo project. Briefing from all parties to the proceeding, including APS, is complete and we expect a decision to be rendered by the EAB before the end of 2016. If the permit is upheld by the EAB, we do not expect a delay in the construction schedule for the project.

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 2018, 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 monitor their energy use and needs, minimize system outage durations, as well as the number of customers that experience outages, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions, including remote meter reading and remote connects and disconnects.

Renewable Energy. The ACC approved the RES in 2006. The renewable energy requirement is 6% of retail electric sales in 2016 and increases annually until it reaches 15% in 2025. In the 2009 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 2015. A component of the RES targets development of distributed energy systems.

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.

The following table summarizes renewable energy sources in APS's renewable portfolio that are in operation and under development as of August 2, 2016.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
Total APS Owned: Solar (a)	189	49 (c)
Purchased Power Agreements:		
Solar	310	—
Wind	289	—
Geothermal	10	—
Biomass	14	—
Biogas	6	—
Total Purchased Power Agreements	629	—
Total Distributed Energy: Solar (b)	525	25 (d)
Total Renewable Portfolio	1,343	74

(a) Included in the 189 MW number is 170 MW of solar resources procured through the 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) This amount represents APS-owned grid scale and distributed generation projects currently under development. Projects include the 40 MW Red Rock Solar Plant and the Solar Partner Program discussed below. Upon completion of construction, these projects will be considered "in operation" for purposes of this table.
(d) Applications received by APS that are not yet installed and online.

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

In accordance with the ACC’s decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned grid scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of grid scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar for research and development purposes that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

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.

In March 2014 the ACC approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

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 approved 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 its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its 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 July 12, 2016, the ACC approved APS's amended DSM Plan and directed APS to spend up to an additional $4 million on a new residential demand response or load management program that facilitates energy storage technology.

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 Utility 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. A formal rulemaking has not been initiated and there has been no additional action on the draft to date. 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.

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. On June 1, 2011, APS filed a rate case with the ACC. APS and other parties to the retail rate case subsequently entered into the 2012 Settlement Agreement detailing the terms upon which the parties have agreed to settle the rate case. See Note 3 for details regarding the 2012 Settlement Agreement terms and 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 excludes amounts that are currently collected on customer bills through adjustor mechanisms. The application requests 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 an incremental effect on customer bills. The average annual customer bill impact of APS's request is an increase of 5.74% (the average annual bill impact for a typical APS

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residential customer is 7.96%). APS's application also addresses rate design changes (residential, commercial and industrial), permission to defer for potential future recovery costs associated with the Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. APS requested that the increase become effective July 1, 2017. On July 22, 2016, the administrative law judge set a procedural schedule for the rate proceedings. The ACC staff and interveners will begin filing their direct testimony on December 21, and the hearing will commence on March 22, 2017. The Commission staff supports completing the case within 12 months. APS cannot predict the outcome of its request.

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 in Note 3.

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 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. APS cannot predict the outcome of either matter.

Net Metering. On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 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. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015 and February 23, 2016, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS actively participated in the related hearings held in March 2016. APS has also intervened in the upcoming Tucson Electric Power Company rate case. On June 24, 2016, APS filed testimony in the Tucson Electric Power Company rate case in support of the Tucson Electric Power Company proposed rate design changes. The outcomes of these proceedings will not directly impact our financial position.

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB"). In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and 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 APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument was conducted on March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

System Benefits Charge. The 2012 Settlement Agreement provides 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.

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 California System Operator Corporation ("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.

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 2013 through 2015, retail electric revenues comprised approximately 93% 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, and the operation of our adjustor 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.

Customer and Sales Growth. Retail customers in APS's service territory increased 1.4% for the six-month period ended June 30, 2016 compared with the prior-year period. For the three years 2013 through 2015, APS's customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 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 0.6% for the six-month period ended June 30, 2016 compared with the prior-year period, reflecting the effects of improving economic conditions and customer growth and an additional day of sales due to the leap year, partially offset by customer conservation and energy efficiency and distributed renewable generation initiatives. For the three years 2013 through 2015, APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average in the range of 0.5-1.5% during 2016 through 2018, 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 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 and Seasonality. 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. Additionally, 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.

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, outages, 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. See Note 3 regarding deferral of certain costs pursuant to an ACC order.

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 11.0% of the assessed value for 2015, 10.7% for 2014 and 10.5% for 2013. 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. (See Note 3 for property tax deferrals contained in the 2012 Settlement Agreement.)

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.

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 retail and wholesale sales supplied to traditional cost-based rate regulation ("Native Load") customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results — Three-month period ended June 30, 2016 compared with three-month period ended June 30, 2015.

Our consolidated net income attributable to common shareholders for the three months ended June 30, 2016 was $121 million, compared with consolidated net income attributable to common shareholders of $123 million for the prior-year period. The results reflect a decrease of approximately $2 million for the regulated electricity segment primarily due to higher operations and maintenance expenses related to employee benefit costs, partially offset by the effects of weather and higher retail sales due to customer growth and changes in customer usage patterns and related pricing.

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

	Three Months Ended June 30, 2016	2015	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$635	$608	$ 27
Operations and maintenance	(242)	(211)	(31)
Depreciation and amortization	(123)	(123)	—
Taxes other than income taxes	(42)	(43)	1
All other income and expenses, net	12	9	3
Interest charges, net of allowance for borrowed funds used during construction	(48)	(44)	(4)
Income taxes	(66)	(68)	2
Less income related to noncontrolling interests (Note 5)	(5)	(5)	—
Regulated electricity segment income	121	123	(2)
All other	—	—	—
Net Income Attributable to Common Shareholders	$121	$123	$ (2)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $27 million higher for the three months ended June 30, 2016 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)		
Effects of weather	$ 23	$ 7	$ 16
Transmission revenues (Note 3):			
Higher retail transmission revenues	16	—	16
FERC disallowance	(12)	—	(12)
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing	7	—	7
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(9)	(10)	1
Palo Verde system benefits charge (offset in depreciation and amortization, see Note 3)	(4)	—	(4)
Miscellaneous items, net	(1)	(4)	3
Total	$ 20	$ (7)	$ 27

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Operations and maintenance. Operations and maintenance expenses increased $31 million for the three months ended June 30, 2016 compared with the prior-year period primarily because of:

- An increase of $18 million for employee benefit costs primarily related to stock compensation and other benefit costs;

- An increase of $10 million in fossil generation costs related to higher planned outage costs;

- An increase of $5 million for corporate support related to costs to support the company's positions on a solar net metering ballot initiative in Arizona, and increased regulatory costs;

- An increase of $4 million related to transmission, distribution and customer service costs primarily related to increased maintenance costs and implementation of new systems;

- A decrease of $10 million related to lower other fossil operating costs; and

- An increase of $4 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses for the three months ended June 30, 2016 were comparable to the prior-year period and included the following:

- An increase of $9 million due to increased plant in service;

- A decrease of $5 million related to the regulatory treatment of the Palo Verde sale leaseback lease extension; and

- A decrease of $4 million due to lower Palo Verde decommissioning expense recovered through system benefits charge (offset in operating revenues).

All other income and expenses, net. All other income and expenses, net, were $3 million higher for the three months ended June 30, 2016 compared with the prior-year period primarily due to the gain on sale of a transmission line.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, increased $4 million for the three months ended June 30, 2016 compared with the prior-year period, primarily because of higher debt balances in the current year.

Operating Results — Six-month period ended June 30, 2016 compared with six-month period ended June 30, 2015.

Our consolidated net income attributable to common shareholders for the six months ended June 30, 2016 was $126 million, compared with consolidated net income attributable to common shareholders of $139 million for the prior-year period. The results reflect a decrease of approximately $13 million for the regulated electricity segment primarily due to higher operations and maintenance expenses related to employee benefit costs, fossil generation costs and transmission, distribution and customer service costs; partially offset by the effects of weather, higher retail transmission revenues, and higher retail sales due to customer growth and changes in customer usage patterns and related pricing.

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

	Six Months Ended June 30,		
	2016	2015	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$1,090	$1,056	$ 34
Operations and maintenance	(485)	(426)	(59)
Depreciation and amortization	(243)	(244)	1
Taxes other than income taxes	(84)	(86)	2
All other income and expenses, net	20	13	7
Interest charges, net of allowance for borrowed funds used during construction	(93)	(88)	(5)
Income taxes	(68)	(76)	8
Less income related to noncontrolling interests (Note 5)	(10)	(9)	(1)
Regulated electricity segment income	127	140	(13)
All other	(1)	(1)	—
Net Income Attributable to Common Shareholders	$126	$139	$ (13)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $34 million higher for the six months ended June 30, 2016 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)		
Effects of weather	$ 29	$ 9	$ 20
Transmission revenues (Note 3):			
Higher retail transmission revenues	19	—	19
FERC disallowance	(12)	—	(12)
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing	15	2	13
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(16)	(17)	1
Palo Verde system benefits charge (offset in depreciation and amortization, see Note 3)	(7)	—	(7)
Miscellaneous items, net	(2)	(2)	—
Total	$ 26	$ (8)	$ 34

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Operations and maintenance. Operations and maintenance expenses increased $59 million for the six months ended June 30, 2016 compared with the prior-year period primarily because of:

- An increase of $27 million for employee benefit costs primarily related to stock compensation and other benefit costs;
- An increase of $15 million in fossil generation costs primarily related to $33 million in higher planned outage costs, partially offset by $18 million of lower other fossil operating costs;
- An increase of $11 million for transmission, distribution, and customer service costs primarily related to increased maintenance costs and implementation of new systems;
- An increase of $5 million for corporate support related to costs to support the company's positions on a solar net metering ballot initiative in Arizona, and increased regulatory costs; and
- An increase of $1 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses decreased $1 million for the six months ended June 30, 2016 compared to the prior-year period primarily related to:

- A decrease of $10 million related to the regulatory treatment of the Palo Verde sale leaseback lease extension;
- A decrease of $7 million due to lower Palo Verde decommissioning expense recovered through system benefits charge (offset in operating revenues); and
- An increase of $16 million due to increased plant in service.

All other income and expenses, net. All other income and expenses, net, were $7 million higher for the six months ended June 30, 2016 compared with the prior-year period primarily due to the gain on sale of a transmission line.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, increased $5 million for the six months ended June 30, 2016 compared with the prior-year period, primarily because of higher debt balances in the current year.

Income Taxes. Income taxes were $8 million lower for the six months ended June 30, 2016 compared with the prior-year period, primarily because of lower taxable income in the current year.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Pinnacle West’s primary cash needs are for dividends to our shareholders and principal and interest payments on our indebtedness. The level of our common stock dividends and future dividend growth will be dependent on declaration by our Board of Directors and based on a number of factors, including our financial condition, payout ratio, free cash flow and other factors.

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At June 30, 2016, APS's common equity ratio, as defined, was 52%. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.9 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.6 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

APS's capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financing and equity infusions from Pinnacle West.

Many of APS's current capital expenditure projects qualify for bonus depreciation. On December 18, 2015, President Obama signed into law the Consolidated Appropriations Act, 2016 (H.R. 2029), which combined the tax and government funding bills (The Protecting Americans from Tax Hikes Act and Omnibus Bill) containing an extension of bonus depreciation through 2019. Enactment of this legislation is expected to generate approximately $375-$425 million of cash tax benefits over the next three years, which is expected to be fully realized by APS and Pinnacle West Consolidated during this time frame. The cash generated by the extension of bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years and reduces rate base for ratemaking purposes. At Pinnacle West Consolidated, the extension of bonus depreciation will, in turn, delay until 2019 full cash realization of approximately $78 million of currently unrealized Investment Tax Credits, which are recorded as a deferred tax asset on the Condensed Consolidated Balance Sheet as of June 30, 2016.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the six months ended June 30, 2016 and 2015 (dollars in millions):

Pinnacle West Consolidated

	Six Months Ended June 30,		Net
	2016	2015	Change
Net cash flow provided by operating activities	$ 422	$ 394	$ 28
Net cash flow used for investing activities	(715)	(509)	(206)
Net cash flow provided by financing activities	297	121	176
Net increase in cash and cash equivalents	$ 4	$ 6	$ (2)

Arizona Public Service Company

	Six Months Ended June 30,		Net
	2016	2015	Change
Net cash flow provided by operating activities	$ 426	$ 406	$ 20
Net cash flow used for investing activities	(700)	(508)	(192)
Net cash flow provided by financing activities	283	106	177
Net increase in cash and cash equivalents	$ 9	$ 4	$ 5

Operating Cash Flows

Six-month period ended June 30, 2016 compared with six-month period ended June 30, 2015. Pinnacle West's consolidated net cash provided by operating activities was $422 million in 2016 compared to $394 million in 2015. The increase of $28 million in net cash provided is primarily due to changes in working capital.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 116% funded as of January 1, 2015 and 2016. Under GAAP, the qualified pension plan was 89% funded as of January 1, 2015 and 88% funded as of January 1, 2016. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made voluntary contributions of $80 million to our pension plan year-to-date in 2016. 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 2016-2018 period. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans.

Investing Cash Flows

Six-month period ended June 30, 2016 compared with six-month period ended June 30, 2015. Pinnacle West's consolidated net cash used for investing activities was $715 million in 2016, compared to $509 million in 2015, an increase of $206 million in net cash used primarily related to increased capital expenditures.

Capital Expenditures. The following table summarizes the estimated capital expenditures for the next three years:

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2016	2017	2018
APS			
Generation:			
Nuclear Fuel	$ 81	$ 78	$ 81
Renewables	107	1	1
Environmental	227	201	103
New Gas Generation	77	235	114
Other Generation	139	146	207
Distribution	359	346	398
Transmission	122	217	139
Other (a)	93	83	81
Total APS	$ 1,205	$ 1,307	$ 1,124

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil, renewable and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. The estimated renewables capital expenditures include a grid scale solar facility. We have not included estimated costs for Cholla's compliance with EPA's regional haze rule since we have challenged the regional haze rule judicially and we have proposed a compromise strategy to EPA, which, if approved, would allow us to avoid expenditures related to environmental control equipment. We are monitoring the status of other environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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. On December 29, 2015, NTEC notified APS of its intent to exercise its option to purchase the 7% interest. 4CA, a wholly-owned subsidiary of Pinnacle West, purchased the El Paso interest on July 6, 2016. The table above does not include capital expenditures related to 4CA's interest in Four Corners Units 4 and 5 of approximately $30 million in 2016 and $25 million in 2017.

Distribution and transmission capital expenditures are comprised of infrastructure additions and upgrades, capital replacements, and new customer construction. Examples of the types of projects included in the forecast include power lines, substations, and line extensions to new residential and commercial developments.

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.

Financing Cash Flows and Liquidity

Six-month period ended June 30, 2016 compared with six-month period ended June 30, 2015. Pinnacle West's consolidated net cash provided by financing activities was $297 million in 2016, compared to $121 million of net cash provided in 2015, an increase of $176 million in net cash provided. The increase in net cash provided by financing activities is primarily due to $268 million lower repayments of long-term debt and a $54 million net change in short-term borrowings, partially offset by $154 million lower issuances of long-term debt.

Significant Financing Activities. On June 22, 2016, the Pinnacle West Board of Directors declared a dividend of $0.625 per share of common stock, payable on September 1, 2016 to shareholders of record on August 1, 2016.

On April 22, 2016, APS entered into a $100 million term loan facility that matures April 22, 2019. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On May 6, 2016, APS issued $350 million of 3.75% unsecured senior notes that mature on May 15, 2046. The net proceeds from the sale were used to redeem and cancel Pollution Control Bonds (see details below), and to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On June 1, 2016, APS redeemed at par and canceled all $64 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series D and E.

On June 1, 2016, APS redeemed at par and canceled all $13 million of the Coconino County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Navajo Project), 2009 Series A.

On August 1, 2016, APS repaid at maturity APS's $250 million aggregate principal amount of 6.25% senior notes due August 1, 2016.

Available Credit Facilities. Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

During the first quarter of 2016, APS increased its commercial paper program from $250 million to $500 million.

On May 13, 2016, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2019, with a new $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 June 30, 2016, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

On May 13, 2016, APS replaced its $500 million revolving credit facility that would have matured in May 2019, with a new $500 million facility that matures in May 2021. At June 30, 2016, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and the $500 million facility that matures in May 2021. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the 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 June 30, 2016, APS had $64 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 separate outstanding letters of credit.

Other Financing Matters. See Note 6 for information related to the change in our margin and collateral accounts.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At June 30, 2016, the ratio was approximately 49% for Pinnacle West and 48% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements and term loan facilities contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

See Note 2 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of July 22, 2016 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	A3	A-	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	A2	A-	A-
Senior unsecured	A2	A-	A
Commercial paper	P-1	A-2	F2
Outlook	Stable	Stable	Stable

Off-Balance Sheet Arrangements

See Note 5 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

There have been no material changes, as of June 30, 2016, outside the normal course of business in contractual obligations from the information provided in our 2015 Form 10-K. See Note 2 for discussion regarding changes in our long-term debt obligations.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. There have been no changes to our critical accounting policies since our 2015 Form 10-K. See "Critical Accounting Policies" in Item 7 of the 2015 Form 10-K for further details about our critical accounting policies.

OTHER ACCOUNTING MATTERS

We are currently evaluating the impacts of adopting the following new accounting standards:

- Stock compensation guidance effective for us January 1, 2017
- Revenue recognition guidance, and related amendments, effective for us January 1, 2018
- Financial instrument recognition and measurement guidance effective for us January 1, 2018
- Lease accounting guidance effective for us January 1, 2019
- Measurement of credit losses on financial instruments effective for us on January 1, 2020

See Note 12 for additional information related to accounting matters.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust fund and benefit plan assets.

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 10 and Note 11) and benefit plan assets. The nuclear decommissioning trust fund and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning and benefit plan costs are recovered in regulated electricity prices.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. Our risk management committee, consisting of officers and key management personnel, oversees company-wide energy risk management activities to ensure compliance with our stated energy risk management policies. We manage risks associated with these market fluctuations by utilizing various commodity instruments that may qualify as derivatives, including futures, forwards, options and swaps. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities.

The following table shows the net pretax changes in mark-to-market of our derivative positions for the six months ended June 30, 2016 and 2015 (dollars in millions):

	Six Months Ended June 30,	
	2016	2015
Mark-to-market of net positions at beginning of year	$ (154)	$ (115)
Decrease (increase) in regulatory asset/liability	70	(18)
Recognized in OCI:		
Mark-to-market losses realized during the period	2	3
Change in valuation techniques	—	—
Mark-to-market of net positions at end of period	$ (82)	$ (130)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at June 30, 2016 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements," in Item 8 of our 2015 Form 10-K and Note 10 for more discussion of our valuation methods.

Source of Fair Value	2016	2017	2018	2019	2020	Total fair value
Observable prices provided by other external sources	$(22)	$(18)	$(11)	$ 1	$ —	$(50)
Prices based on unobservable inputs	(8)	(7)	(8)	(7)	(2)	(32)
Total by maturity	$(30)	$(25)	$(19)	$(6)	$(2)	$(82)

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Condensed Consolidated Balance Sheets at June 30, 2016 and December 31, 2015 (dollars in millions):

	June 30, 2016 Gain (Loss)		December 31, 2015 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) or OCI (a)				
Electricity	$ 2	$ (2)	$ 2	$ (2)
Natural gas	47	(47)	35	(35)
Total	$ 49	$ (49)	$ 37	$ (37)

(a) These contracts are economic hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

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Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 6 for a discussion of our credit valuation adjustment policy.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Key Financial Drivers" and "Market and Credit Risks" in Item 2 above for a discussion of quantitative and qualitative disclosures about market risks.

Item 4. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term "disclosure controls and procedures" means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") (15 U.S.C. 78a et seq.), is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of June 30, 2016. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of APS's disclosure controls and procedures as of June 30, 2016. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

The term "internal control over financial reporting" (defined in SEC Rule 13a-15(f)) refers to the process of a company that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended June 30, 2016 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

PART II -- OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 of the 2015 Form 10-K with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 7 for information regarding environmental matters and Superfund-related matters.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Overview - Areas of Business Focus - Operational Performance, Reliability and Recent Developments - Natural Gas" for information regarding the appeal of a permit related to our Ocotillo modernization project.

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A — Risk Factors in the 2015 Form 10-K, which could materially affect the business, financial condition, cash flows or future results of Pinnacle West and APS. The risks described in the 2015 Form 10-K are not the only risks facing Pinnacle West and APS. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect the business, financial condition, cash flows and/or operating results of Pinnacle West and APS.

Item 5. OTHER INFORMATION

Peabody Bankruptcy

On April 13, 2016, Peabody Energy Corporation and certain affiliated entities filed a petition for relief under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Missouri. Under a Coal Supply Agreement, dated December 21, 2005, Peabody supplied coal to APS and PacifiCorp (collectively, the “Buyers”) for use at the Cholla power plant in Arizona. APS believes that the Coal Supply Agreement terminated automatically on April 13, 2016 as a result of Peabody's bankruptcy filing. The Buyers filed a motion requesting that the Bankruptcy Court enter an order determining that the Buyers are authorized to enforce the termination provisions in the Coal Supply Agreement.

On May 13, 2016, Peabody filed a complaint against the Buyers in the bankruptcy court in which Peabody alleges that the Buyers have breached the Agreement. Peabody requests substantial, but unspecified, monetary damages from the Buyers. Peabody and the Buyers have agreed to commence non-binding mediation, failing which a trial is expected to occur in November 2016. APS cannot predict the outcome of this matter.

Subpoenas

In June 2016, Pinnacle West received two grand jury subpoenas issued in connection with an investigation by the office of the United States Attorney for the District of Arizona. The subpoenas seek information principally pertaining to the 2014 statewide election races in Arizona for Secretary of State and for positions on the ACC. The subpoenas request records involving certain Pinnacle West officers and employees, including the Company’s Chief Executive Officer, as well as communications between Pinnacle West personnel and a former ACC Commissioner. Pinnacle West is cooperating fully with the United States Attorney’s office in this matter.

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Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
10.1	Pinnacle West	Five-Year Credit Agreement dated as of May 13, 2016, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto
10.2	Pinnacle West APS	Five-Year Credit Agreement dated as of May 13, 2016, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto
12.1	Pinnacle West	Ratio of Earnings to Fixed Charges
12.2	APS	Ratio of Earnings to Fixed Charges
12.3	Pinnacle West	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements
31.1	Pinnacle West	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.2	Pinnacle West	Certificate of James R. Hatfield, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.3	APS	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.4	APS	Certificate of James R. Hatfield, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
32.1*	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	Pinnacle West APS	XBRL Instance Document
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document

101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document

*Furnished herewith as an Exhibit.

In addition, Pinnacle West and APS hereby incorporate the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit(1)	Date Filed
3.1	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of May 19, 2010	3.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2010
3.2	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/7/2008
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.4	APS	Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012	3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2012
3.5	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File Nos. 1-8962 and 1-4473	2/20/2009

(1) Reports filed under File Nos. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: August 2, 2016 By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: August 2, 2016 By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)