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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2023

OR

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

For the transition period from to

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	PNW	The New York Stock Exchange

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

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

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

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

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

PINNACLE WEST CAPITAL CORPORATION

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

Emerging growth company ☐

ARIZONA PUBLIC SERVICE COMPANY

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

Emerging growth company ☐

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

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

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

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

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of October 27, 2023:	113,398,346
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of October 27, 2023:	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 quarterly report on 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 of this report also includes Combined Notes to Condensed Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume," "project," "anticipate," "goal," "seek," "strategy," "likely," "should," "will," "could," 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, 2022 ("2022 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:

- the current economic environment and its effects, such as lower economic growth, a tight labor market, inflation, supply chain delays, increased expenses, volatile capital markets, or other unpredictable effects;
- 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 (including large increases in ambient temperatures), the general economy or social conditions, customer and sales growth (or decline), the effects of energy conservation measures and distributed generation, and technological advancements;
- the potential effects of climate change on our electric system, including as a result of weather extremes, such as prolonged drought and high temperature variations in the area where APS conducts its business;
- 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 or interpretations of existing legislation or regulations, including those relating to environmental requirements, regulatory and energy 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 through our rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- the ability of APS to achieve its clean energy goals (including a goal by 2050 of 100% clean, carbon-free electricity) and, if these goals are achieved, the impact of such achievement on APS, its customers, and its business, financial condition, and results of operations;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona;
- the direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, terrorist attack, physical attack, severe storms, or other catastrophic events, such as fires, explosions, pandemic health events, or similar occurrences;
- the development of new technologies which may affect electric sales or delivery, including as a result of delays in the development and application of new technologies;
- the cost of debt, including increased cost as a result of rising interest rates, and equity capital and the ability to access capital markets when required;
- environmental, economic, and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions ("GHG");
- 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 landowners 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 2022 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, 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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
OPERATING REVENUES (Note 2)	$ 1,637,759	$ 1,469,871	$ 3,704,417	$ 3,315,071
OPERATING EXPENSES				
Fuel and purchased power	614,520	556,571	1,416,778	1,174,027
Operations and maintenance	250,019	251,663	777,337	715,392
Depreciation and amortization	203,438	190,389	590,445	563,491
Taxes other than income taxes	53,169	53,475	167,949	165,591
Other expenses	350	200	1,648	1,410
Total	1,121,496	1,052,298	2,954,157	2,619,911
OPERATING INCOME	516,263	417,573	750,260	695,160
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	11,976	9,133	40,071	30,966
Pension and other postretirement non-service credits - net (Note 5)	10,174	24,673	30,513	73,739
Other income (Note 9)	15,941	2,219	28,424	5,605
Other expense (Note 9)	(6,972)	(6,745)	(15,916)	(14,751)
Total	31,119	29,280	83,092	95,559
INTEREST EXPENSE				
Interest charges	96,909	72,185	278,860	205,677
Allowance for borrowed funds used during construction	(9,092)	(8,692)	(34,131)	(19,047)
Total	87,817	63,493	244,729	186,630
INCOME BEFORE INCOME TAXES	459,565	383,360	588,623	604,089
INCOME TAXES	57,045	52,728	74,125	83,577
NET INCOME	402,520	330,632	514,498	520,512
Less: Net income attributable to noncontrolling interests (Note 6)	4,306	4,306	12,918	12,918
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 398,214	$ 326,326	$ 501,580	$ 507,594
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING - BASIC	113,464	113,211	113,411	113,162
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING - DILUTED	113,838	113,463	113,718	113,376
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING				
Net income attributable to common shareholders - basic	$ 3.51	$ 2.88	$ 4.42	$ 4.49
Net income attributable to common shareholders - diluted	$ 3.50	$ 2.88	$ 4.41	$ 4.48

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
NET INCOME	$ 402,520	$ 330,632	$ 514,498	$ 520,512
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments net unrealized gain, net of tax benefit (expense) of $(217), $(169), $(161) and $(582)	659	513	489	1,772
Pension and other postretirement benefit activity, net of tax benefit (expense) of $(164), $(329), $(168) and $69	498	1,001	512	(211)
Total other comprehensive income	1,157	1,514	1,001	1,561
COMPREHENSIVE INCOME	403,677	332,146	515,499	522,073
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,306	12,918	12,918
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 399,371	$ 327,840	$ 502,581	$ 509,155

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

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

	September 30, 2023	December 31, 2022
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 15,108	$ 4,832
Customer and other receivables	664,936	453,209
Accrued unbilled revenues	226,998	164,764
Allowance for doubtful accounts (Note 2)	(20,648)	(23,778)
Materials and supplies (at average cost)	443,852	410,481
Income tax receivable	—	14,086
Fossil fuel (at average cost)	49,977	40,155
Assets from risk management activities (Note 7)	11,376	87,835
Assets held for sale (Note 16)	31,706	—
Deferred fuel and purchased power regulatory asset (Note 4)	526,666	460,561
Other regulatory assets (Note 4)	103,653	78,318
Other current assets	108,314	60,091
Total current assets	2,161,938	1,750,554
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,120,463	1,073,410
Other special use funds (Notes 11 and 12)	368,159	347,231
Assets from risk management activities (Note 7)	3,171	44,394
Other assets	102,863	125,672
Total investments and other assets	1,594,656	1,590,707
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	23,939,969	22,452,146
Accumulated depreciation and amortization	(8,319,351)	(7,929,878)
Net	15,620,618	14,522,268
Construction work in progress	1,536,323	1,882,791
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	87,394	90,296
Intangible assets, net of accumulated amortization	249,480	258,880
Nuclear fuel, net of accumulated amortization	112,956	100,119
Total property, plant and equipment	17,606,771	16,854,354
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,303,244	1,283,221
Operating lease right-of-use assets (Note 14)	1,307,643	801,688
Assets for pension and other postretirement benefits (Note 5)	407,065	396,599
Other	53,109	46,282
Total deferred debits	3,071,061	2,527,790
TOTAL ASSETS	$ 24,434,426	$ 22,723,405

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

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

	September 30, 2023	December 31, 2022
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 404,971	$ 430,425
Accrued taxes	265,463	164,440
Accrued interest	76,192	61,217
Common dividends payable	—	97,895
Short-term borrowings (Note 3)	424,000	340,720
Current maturities of long-term debt (Note 3)	250,000	50,685
Customer deposits	40,557	41,769
Liabilities from risk management activities (Note 7)	42,732	37,697
Liabilities for asset retirements (Note 15)	16,445	12,232
Operating lease liabilities (Note 14)	90,578	105,210
Regulatory liabilities (Note 4)	226,989	271,575
Other current liabilities	130,415	148,276
Total current liabilities	1,968,342	1,762,141
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	8,164,372	7,741,286
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,408,218	2,384,421
Regulatory liabilities (Note 4)	1,919,281	2,061,776
Liabilities for asset retirements (Note 15)	878,735	785,530
Liabilities for pension benefits (Note 5)	110,472	116,286
Liabilities from risk management activities (Note 7)	13,012	4,749
Customer advances	520,180	422,103
Coal mine reclamation	182,816	179,255
Deferred investment tax credit	253,680	180,677
Unrecognized tax benefits	33,738	38,658
Operating lease liabilities (Note 14)	1,204,639	639,247
Other	288,736	247,400
Total deferred credits and other	7,813,507	7,060,102
COMMITMENTS AND CONTINGENCIES (Note 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 113,414,167 and 113,247,189 issued at respective dates	2,744,501	2,724,740
Treasury stock at cost; 75,767 and 73,613 shares at respective dates	(5,328)	(5,005)
Total common stock	2,739,173	2,719,735
Retained earnings	3,665,946	3,360,347
Accumulated other comprehensive loss (Note 13)	(30,434)	(31,435)
Total shareholders' equity	6,374,685	6,048,647
Noncontrolling interests (Note 6)	113,520	111,229
Total equity	6,488,205	6,159,876
TOTAL LIABILITIES AND EQUITY	$ 24,434,426	$ 22,723,405

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)

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 514,498	$ 520,512
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale relating to BCE	(6,423)	—
Depreciation and amortization including nuclear fuel	636,224	612,958
Deferred fuel and purchased power	(486,382)	(228,483)
Deferred fuel and purchased power amortization	420,277	171,607
Allowance for equity funds used during construction	(40,071)	(30,966)
Deferred income taxes	(35,258)	43,440
Deferred investment tax credit	73,003	(7,152)
Change in derivative instruments fair value	(778)	—
Stock compensation	12,304	12,824
Changes in current assets and liabilities:		
Customer and other receivables	(214,291)	(213,181)
Accrued unbilled revenues	(62,234)	(87,043)
Materials, supplies and fossil fuel	(43,193)	(72,623)
Income tax receivable	14,087	7,514
Other current assets	(11,585)	54,272
Accounts payable	(79,603)	137,433
Accrued taxes	101,022	117,044
Other current liabilities	18,074	12,575
Change in margin and collateral accounts - assets	(418)	8,832
Change in other long-term assets	(71,897)	208,599
Change in operating lease assets	89,836	98,081
Change in other long-term liabilities	75,541	(235,986)
Change in operating lease liabilities	(68,834)	(98,343)
Net cash provided by operating activities	833,899	1,031,914
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,314,529)	(1,276,861)
Contributions in aid of construction	112,762	103,366
Proceeds from sale relating to BCE	17,500	—
Allowance for borrowed funds used during construction	(34,131)	(18,381)
Proceeds from nuclear decommissioning trusts sales and other special use funds	1,165,668	911,003
Investment in nuclear decommissioning trusts and other special use funds	(1,181,386)	(929,965)
Other	(1,788)	(11,057)
Net cash used for investing activities	(1,235,904)	(1,221,895)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	689,349	455,628
Short-term borrowing and (repayments) - net	56,400	174,820
Dividends paid on common stock	(288,456)	(282,838)
Repayment of long-term debt	(32,740)	(150,000)
Common stock equity issuances and (purchases) - net	(1,644)	62
Distributions to noncontrolling interests	(10,628)	(10,628)
Net cash provided by financing activities	412,281	187,044
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	10,276	(2,937)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,832	9,969
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 15,108	$ 7,032

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

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

	Three Months Ended September 30, 2023							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, June 30, 2023	113,386,894	$2,736,112	(75,767)	$ (5,328)	$ 3,267,731	$ (31,591)	$ 109,213	$ 6,076,137
Net income		—		—	398,214	—	4,306	402,520
Other comprehensive income		—		—	—	1,157	—	1,157
Issuance of common stock	27,273	8,389		—	—	—	—	8,389
Other		—		—	1	—	1	2
Balance, September 30, 2023	113,414,167	$2,744,501	(75,767)	$ (5,328)	$ 3,665,946	$ (30,434)	$ 113,520	$ 6,488,205

	Three Months Ended September 30, 2022							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, June 30, 2022	113,078,049	$2,712,297	(41,531)	$ (2,976)	$ 3,253,772	$ (54,814)	$ 113,244	$ 6,021,523
Net income		—		—	326,326	—	4,306	330,632
Other comprehensive income		—		—	—	1,514	—	1,514
Issuance of common stock	30,679	8,067		—	—	—	—	8,067
Purchase of treasury stock (a)		—	(3,735)	(279)	—	—	—	(279)
Reissuance of treasury stock for stock-based compensation and other		—	9,062	652	—	—	—	652
Other		—		—	4	—	—	4
Balance, September 30, 2022	113,108,728	$2,720,364	(36,204)	$ (2,603)	$ 3,580,102	$ (53,300)	$ 117,550	$ 6,362,113

(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.

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

	Nine Months Ended September 30, 2023							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2022	113,247,189	$2,724,740	(73,613)	$ (5,005)	$ 3,360,347	$ (31,435)	$ 111,229	$ 6,159,876
Net income		—		—	501,580	—	12,918	514,498
Other comprehensive income		—		—	—	1,001	—	1,001
Dividends on common stock ($1.73 per share)		—		—	(195,981)	—	—	(195,981)
Issuance of common stock	166,978	19,761		—	—	—	—	19,761
Purchase of treasury stock (a)		—	(34,675)	(2,610)	—	—	—	(2,610)
Reissuance of treasury stock for stock-based compensation and other		—	32,521	2,287	—	—	—	2,287
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Other		—		—	—	—	1	1
Balance, September 30, 2023	113,414,167	$2,744,501	(75,767)	$ (5,328)	$ 3,665,946	$ (30,434)	$ 113,520	$ 6,488,205

	Nine Months Ended September 30, 2022							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2021	113,014,528	$2,702,743	(87,608)	$ (6,401)	$ 3,264,719	$ (54,861)	$ 115,260	$ 6,021,460
Net income		—		—	507,594	—	12,918	520,512
Other comprehensive income		—		—	—	1,561	—	1,561
Dividends on common stock ($1.70 per share)		—		—	(192,213)	—	—	(192,213)
Issuance of common stock	94,200	17,621		—	—	—	—	17,621
Purchase of treasury stock (a)		—	(28,620)	(1,994)	—	—	—	(1,994)
Reissuance of treasury stock for stock-based compensation and other		—	80,024	5,792	—	—	—	5,792
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Other		—		—	2	—	—	2
Balance, September 30, 2022	113,108,728	$2,720,364	(36,204)	$ (2,603)	$ 3,580,102	$ (53,300)	$ 117,550	$ 6,362,113

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
OPERATING REVENUES (Note 2)	$1,637,759	$1,469,871	$3,704,417	$3,315,071
OPERATING EXPENSES				
Fuel and purchased power	614,520	556,571	1,416,778	1,174,027
Operations and maintenance	247,200	248,808	765,717	705,683
Depreciation and amortization	203,417	190,368	590,381	563,427
Taxes other than income taxes	53,154	53,456	167,908	165,509
Other expenses	350	200	1,648	1,410
Total	1,118,641	1,049,403	2,942,432	2,610,056
OPERATING INCOME	519,118	420,468	761,985	705,015
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	11,976	9,133	40,071	30,966
Pension and other postretirement non-service credits - net (Note 5)	10,408	24,791	31,209	74,080
Other income (Note 9)	8,720	1,661	19,487	4,209
Other expense (Note 9)	(3,633)	(3,023)	(10,385)	(7,657)
Total	27,471	32,562	80,382	101,598
INTEREST EXPENSE				
Interest charges	83,433	66,296	238,385	192,828
Allowance for borrowed funds used during construction	(8,701)	(8,269)	(29,597)	(18,381)
Total	74,732	58,027	208,788	174,447
INCOME BEFORE INCOME TAXES	471,857	395,003	633,579	632,166
INCOME TAXES	65,734	59,004	89,244	93,385
NET INCOME	406,123	335,999	544,335	538,781
Less: Net income attributable to noncontrolling interests (Note 6)	4,306	4,306	12,918	12,918
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 401,817	$ 331,693	$ 531,417	$ 525,863

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
NET INCOME	$ 406,123	$ 335,999	$ 544,335	$ 538,781
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX				
Pension and other postretirement benefits activity, net of tax benefit (expense) of $(146), $(300), $(162) and $142	444	909	493	(432)
Total other comprehensive income (loss)	444	909	493	(432)
COMPREHENSIVE INCOME	406,567	336,908	544,828	538,349
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,306	12,918	12,918
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 402,261	$ 332,602	$ 531,910	$ 525,431

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

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

	September 30, 2023	December 31, 2022
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 23,936,507	$ 22,448,685
Accumulated depreciation and amortization	(8,316,036)	(7,926,575)
Net	15,620,471	14,522,110
Construction work in progress	1,536,233	1,829,004
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	87,394	90,296
Intangible assets, net of accumulated amortization	249,324	258,725
Nuclear fuel, net of accumulated amortization	112,956	100,119
Total property, plant and equipment	17,606,378	16,800,254
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,120,463	1,073,410
Other special use funds (Notes 11 and 12)	368,159	347,231
Assets from risk management activities (Note 7)	3,171	44,394
Other assets	44,134	43,344
Total investments and other assets	1,535,927	1,508,379
CURRENT ASSETS		
Cash and cash equivalents	14,447	4,042
Customer and other receivables	661,934	448,880
Accrued unbilled revenues	226,998	164,764
Allowance for doubtful accounts (Note 2)	(20,648)	(23,778)
Materials and supplies (at average cost)	443,852	410,481
Fossil fuel (at average cost)	49,977	40,155
Income tax receivable	1,102	1,102
Assets from risk management activities (Note 7)	11,376	87,704
Deferred fuel and purchased power regulatory asset (Note 4)	526,666	460,561
Other regulatory assets (Note 4)	103,653	78,318
Other current assets	65,221	50,043
Total current assets	2,084,578	1,722,272
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,303,244	1,283,221
Operating lease right-of-use assets (Note 14)	1,306,217	796,544
Assets for pension and other postretirement benefits (Note 5)	399,518	389,142
Other	52,689	44,040
Total deferred debits	3,061,668	2,512,947
TOTAL ASSETS	$ 24,288,551	$ 22,543,852

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

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

	September 30, 2023	December 31, 2022
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	3,321,696	3,171,696
Retained earnings	3,942,881	3,607,464
Accumulated other comprehensive loss (Note 13)	(15,103)	(15,596)
Total shareholder equity	7,427,636	6,941,726
Noncontrolling interests (Note 6)	113,520	111,229
Total equity	7,541,156	7,052,955
Long-term debt less current maturities (Note 3)	7,040,851	6,793,529
Total capitalization	14,582,007	13,846,484
CURRENT LIABILITIES		
Short-term borrowings (Note 3)	313,000	325,000
Current maturities of long-term debt (Note 3)	250,000	—
Accounts payable	399,302	417,732
Accrued taxes	273,630	156,746
Accrued interest	74,193	60,518
Common dividends payable	—	97,900
Customer deposits	40,557	41,769
Liabilities from risk management activities (Note 7)	42,732	37,697
Liabilities for asset retirements (Note 15)	16,445	12,232
Operating lease liabilities (Note 14)	90,307	104,728
Regulatory liabilities (Note 4)	226,989	271,575
Other current liabilities	177,126	144,733
Total current liabilities	1,904,281	1,670,630
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,416,837	2,385,647
Regulatory liabilities (Note 4)	1,919,281	2,061,776
Liabilities for asset retirements (Note 15)	878,735	785,530
Liabilities for pension benefits (Note 5)	104,029	108,068
Liabilities from risk management activities (Note 7)	13,012	3,840
Customer advances	520,180	422,103
Coal mine reclamation	182,816	179,255
Deferred investment tax credit	253,680	180,677
Unrecognized tax benefits	40,439	38,658
Operating lease liabilities (Note 14)	1,203,252	634,199
Other	270,002	226,985
Total deferred credits and other	7,802,263	7,026,738
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL LIABILITIES AND EQUITY	$ 24,288,551	$ 22,543,852

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

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

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 544,335	$ 538,781
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	636,160	612,894
Deferred fuel and purchased power	(486,382)	(228,483)
Deferred fuel and purchased power amortization	420,277	171,607
Allowance for equity funds used during construction	(40,071)	(30,966)
Deferred income taxes	(20,997)	(9,257)
Deferred investment tax credit	73,003	(7,152)
Changes in current assets and liabilities:		
Customer and other receivables	(215,618)	(213,458)
Accrued unbilled revenues	(62,234)	(87,043)
Materials, supplies and fossil fuel	(43,193)	(72,623)
Income tax receivable	—	10,756
Other current assets	(15,680)	39,479
Accounts payable	(71,028)	133,357
Accrued taxes	116,884	170,767
Other current liabilities	22,457	21,134
Change in margin and collateral accounts - assets	23	8,832
Change in other long-term assets	(65,067)	219,472
Change in operating lease assets	89,608	97,858
Change in other long-term liabilities	76,592	(237,486)
Change in operating lease liabilities	(68,591)	(98,113)
Net cash provided by operating activities	890,478	1,040,356
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,293,670)	(1,254,693)
Contributions in aid of construction	112,762	103,366
Allowance for borrowed funds used during construction	(29,597)	(18,381)
Proceeds from nuclear decommissioning trusts sales and other special use funds	1,165,668	911,003
Investment in nuclear decommissioning trusts and other special use funds	(1,181,386)	(929,965)
Other	(877)	570
Net cash used for investing activities	(1,227,100)	(1,188,100)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	496,025	128,000
Short-term borrowings and (repayments) - net	5,530	164,300
Equity infusion	150,000	150,000
Dividends paid on common stock	(293,900)	(288,000)
Distributions to noncontrolling interests	(10,628)	(10,628)
Net cash provided by financing activities	347,027	143,672
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	10,405	(4,072)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,042	9,374
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 14,447	$ 5,302

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)

	Three Months Ended September 30, 2023						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, June 30, 2023	71,264,947	$ 178,162	$ 3,321,696	$ 3,541,062	$ (15,547)	$ 109,213	$ 7,134,586
Net income		—	—	401,817	—	4,306	406,123
Other comprehensive income		—	—	—	444	—	444
Other		—	—	2	—	1	3
Balance, September 30, 2023	71,264,947	$ 178,162	$ 3,321,696	$ 3,942,881	$ (15,103)	$ 113,520	$ 7,541,156

	Three Months Ended September 30, 2022						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, June 30, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,472,403	$ (36,221)	$ 113,244	$ 6,899,284
Net income		—	—	331,693	—	4,306	335,999
Other comprehensive income		—	—	—	909	—	909
Other		—	—	2	—	—	2
Balance, September 30, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,804,098	$ (35,312)	$ 117,550	$ 7,236,194

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)

	Nine Months Ended September 30, 2023						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,607,464	$ (15,596)	$ 111,229	$ 7,052,955
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net Income		—	—	531,417	—	12,918	544,335
Other comprehensive income		—	—	—	493	—	493
Dividends on common stock		—		(196,000)	—	—	(196,000)
Capital activities by noncontrolling interests		—	—	—	—	(10,628)	(10,628)
Other		—	—	—	—	1	1
Balance, September 30, 2023	71,264,947	$ 178,162	$ 3,321,696	$ 3,942,881	$ (15,103)	$ 113,520	$ 7,541,156

	Nine Months Ended September 30, 2022						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2021	71,264,947	$ 178,162	$ 3,021,696	$ 3,470,235	$ (34,880)	$ 115,260	$ 6,750,473
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net Income		—	—	525,863	—	12,918	538,781
Other comprehensive loss		—	—	—	(432)	—	(432)
Dividends on common stock		—	—	(192,000)	—	—	(192,000)
Capital activities by noncontrolling interests		—	—	—	—	(10,628)	(10,628)
Balance, September 30, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,804,098	$ (35,312)	$ 117,550	$ 7,236,194

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

The unaudited condensed consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, 4C Acquisition, LLC ("4CA"), Bright Canyon Energy Corporation ("BCE"), Pinnacle West Power, LLC ("PNW Power"), and El Dorado Investment Company ("El Dorado"). PNW Power is a new wholly-owned subsidiary that was created in September 2023 to hold certain investments in wind and transmission joint projects that were previously held in BCE. See Note 16 for more information. See Note 8 for more information on 4CA matters. 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 Generating Station ("Palo Verde") sale leaseback variable interest entities ("VIEs"). See Note 6 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 2022 Form 10-K.

On June 30, 2020, the United States Federal Energy Regulatory Commission ("FERC") issued an order granting a waiver request related to the existing Allowance for Funds Used During Construction ("AFUDC") rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 31, 2022. The order provided a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacted the AFUDC composite rate in 2021 and for the three-month period ended March 31, 2022. Furthermore, the change in the composite rate calculation did not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
	2023	2022
Cash paid during the period for:		
Income taxes, net of refunds	$ 19	$ 4,784
Interest, net of amounts capitalized	222,715	177,767
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 169,148	$ 112,579
BCE Sale non-cash consideration (Note 16)	34,162	—

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

	Nine Months Ended September 30,	
	2023	2022
Cash paid during the period for:		
Income taxes, net of refunds	$ 1,233	$ 12,327
Interest, net of amounts capitalized	191,095	167,854
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 169,131	$ 112,574

2. Revenue

Sources of Revenue

The following table provides detail of Pinnacle West's consolidated revenue disaggregated by revenue sources (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Retail Electric Service				
Residential	$ 883,393	$ 743,061	$ 1,835,432	$ 1,647,996
Non-Residential	649,164	547,979	1,572,013	1,370,164
Wholesale Energy Sales	57,801	139,741	180,686	198,546
Transmission Services for Others	43,286	36,321	108,229	91,165
Other Sources	4,115	2,769	8,057	7,200
Total operating revenues	$ 1,637,759	$ 1,469,871	$ 3,704,417	$ 3,315,071

Retail Electric Revenue. All of Pinnacle West's retail electric revenue is generated by APS. Retail electric revenue is generated by the sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered, or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms.

Wholesale Energy Sales and Transmission Services for Others. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities primarily consist of managing fuel and purchased power risks in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

In the electricity business, some contracts to purchase energy are settled by netting against other contracts to sell electricity. This is referred to as a book-out, and usually occurs in contracts that have the same terms (product type, quantities, and delivery points) and for which power does not flow. We net these book-outs, which reduces both wholesale revenues and fuel and purchased power costs.

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the three and nine months ended September 30, 2023 were $1,635 million and $3,668 million, respectively, and for the three and nine months ended September 30, 2022 were $1,465 million and $3,299 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three and nine months ended September 30, 2023, our revenues that do not qualify as revenue from contracts with customers were $3 million and $36 million, respectively, and for the three and nine months ended September 30, 2022 were $5 million and $16 million, respectively. This amount includes revenues related to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 4 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Condensed Consolidated Balance Sheets as of September 30, 2023, or December 31, 2022.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. We continue to monitor the impacts of our disconnection policies, payment arrangements, among other considerations impacting our estimated write-off factor, and allowance for doubtful accounts.

The following table provides a rollforward of Pinnacle West's allowance for doubtful accounts (dollars in thousands):

	September 30, 2023	December 31, 2022
Allowance for doubtful accounts, balance at beginning of period	$ 23,778	$ 25,354
Bad debt expense	15,159	17,006
Actual write-offs	(18,289)	(18,582)
Allowance for doubtful accounts, balance at end of period	$ 20,648	$ 23,778

3. Long-Term Debt and Liquidity Matters

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

Pinnacle West

On April 10, 2023, Pinnacle West replaced its $200 million revolving credit facility that would have matured on May 28, 2026, with a new $200 million revolving credit facility that matures on April 10, 2028. Pinnacle West has the option to increase the amount of the facility up to a total of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings and the agreement includes a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. The facility is available to support Pinnacle West's general corporate purposes, including support for Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credit. At September 30, 2023, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $111 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on September 30, 2023, was 5.45%

On December 16, 2022, Pinnacle West entered into a $175 million term loan facility that matures December 16, 2024. The proceeds were received on January 6, 2023 and used for general corporate purposes. We recognized the term loan facility as long-term debt upon settlement on January 6, 2023.

APS

On April 10, 2023, APS replaced its two $500 million revolving credit facilities that would have matured on May 28, 2026, with a new $1.25 billion revolving credit facility that matures on April 10, 2028. APS has the option to increase the amount of the facility up to a maximum of $400 million, for a total of $1.65 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 and the agreement includes a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. This facility is available to support APS's general corporate purposes, including support for APS's commercial paper program, which was increased from $750 million to $1 billion on April 10, 2023, for bank borrowings or for issuances of letters of credit. At September 30, 2023, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $313 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on September 30, 2023, was 5.44%.

On January 6, 2023, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

On June 30, 2023, APS issued $500 million of 5.55% unsecured senior notes that mature August 1, 2033. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper and for general corporate purposes.

See "Financial Assurances" in Note 8 for a discussion of other outstanding letters of credit.

BCE

On February 11, 2022, a special purpose subsidiary of BCE entered into a credit agreement to finance capital expenditures and related costs for the development of a 31 megawatt ("MW") solar and 20 megawatt hour ("MWh") battery storage project in Los Alamitos, California ("Los Alamitos"). The credit agreement consisted of an equity bridge loan facility, a non-recourse construction facility, a letter of credit facility, and a related interest rate swap. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement with Ameresco, Inc. ("Ameresco"), pursuant to which we agreed to sell all our equity interest in BCE to Ameresco (the "BCE Sale"). See Note 16. As a part of the BCE Sale closing, the $36 million construction facility, the letter of credit facility, and the interest rate swap were transferred to Ameresco. On August 4, 2023, concurrent with the BCE Sale, PNW paid in full the outstanding $31 million equity bridge loan balance. As of September 30, 2023, there is no outstanding balance on our Condensed Consolidated Balance Sheets relating to this credit agreement.

On April 18, 2023, Pinnacle West issued performance guarantees in connection with BCE's Kūpono Solar investment project financing. BCE holds an equity method investment relating to the Kūpono Solar project. BCE's investment in the Kūpono Solar project is included in the BCE Sale relating to the stages that have not closed as of September 30, 2023. See Note 8.

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table presents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	As of September 30, 2023		As of December 31, 2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 1,123,521	$ 1,087,405	$ 947,892	$ 905,525
APS	7,290,851	5,969,892	6,793,529	5,629,491
BCE	—	—	50,550	50,685
Total	$ 8,414,372	$ 7,057,297	$ 7,791,971	$ 6,585,701

4. Regulatory Matters

2022 Retail Rate Case

APS filed an application with the ACC on October 28, 2022 (the "2022 Rate Case") seeking an increase in annual retail base rates on the date rates become effective ("Day 1") of a net $460 million. This Day 1 net impact represents a total base revenue deficiency of $772 million offset by proposed adjustor transfers of cost recovery to annual retail rates and adjustor mechanism modifications. The average annual customer bill impact of APS's request on Day 1 is an increase of 13.6%.

The principal provisions of APS's application are:

- a test year comprised of twelve months ended June 30, 2022, adjusted as described below;
- an original cost rate base of $10.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	48.07 %	3.85 %
Common stock equity	51.93 %	10.25 %
Weighted-average cost of capital		7.17 %

- 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 rate of $0.038321 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- modification of its adjustment mechanisms including:
  - eliminate the Environmental Improvement Surcharge ("EIS") and collect costs through base rates,
  - eliminate the Lost Fixed Cost Recovery ("LFCR") mechanism and collect costs through base rates and the Demand Side Management Adjustment Charge ("DSMAC"),
  - maintain as inactive the Tax Expense Adjustor Mechanism ("TEAM"),
  - maintain the Transmission Cost Adjustment ("TCA") mechanism,
  - modify the performance incentive in the DSMAC, and
  - modify the Renewable Energy Adjustment Charge ("REAC") to include recovery of capital carrying costs of APS owned renewable and storage resources;
- changes to its limited-income program, including a second tier to provide an additional discount for customers with greater need; and
- twelve months of post-Test Year plant investments to reflect used and useful projects that will be placed into service prior to July 1, 2023.

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On June 5, 2023 and June 15, 2023, the ACC Staff, the Residential Utility Consumer Office (“RUCO”) and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommends, among other things, (i) a $251 million revenue increase or, as an alternative, a $312 million revenue increase, (ii) a 9.6% return on equity, (iii) a 0.0% fair value increment or, as an alternative, a 0.75% fair value increment, and (iv) a continuation of a 12-month post-test year plant. RUCO recommends, among other things, (i) an $84.9 million revenue increase, (ii) an 8.2% return on equity or, as an alternative, an 8.7% return on equity if the ACC imputes a hypothetical capital structure with a 46% equity layer, (iii) a fair value increment of 0.0%, and (iv) a reduction of post-test year plant to six months.

On July 12, 2023, APS filed rebuttal testimony addressing the ACC Staff and intervenors’ direct testimonies. The principal provisions of APS’s rebuttal testimony are:

- reducing the revenue requirement increase to $383.1 million, which reduced the average annual customer bill impact to an increase of 11.3%;
- maintaining a return on equity request of 10.25%;
- reducing the increment of fair value rate base return to 0.5% from 1.0%;
- maintaining a post-test year plant request of 12 months, plus the Four Corners Effluent Limitation Guidelines (“ELG”) project;
- withdrawing the Payment Fee Removal Proposal (net reduction) which was originally requested in APS’s initial application;
- maintaining the LFCR mechanism and DSMAC as separate adjustors;
- increasing the Power Supply Adjustment (“PSA”) annual rate change limit from $0.004/kWh to $0.006/kWh;
- proposing a new System Reliability Benefit (“SRB”) recovery mechanism;
- maintaining the REAC in its current state;
- maintaining adjustor base transfers and elimination of EIS; and
- maintaining the request to recover Coal Community Transition (“CCT”) funding.

On July 26, 2023, the ACC Staff, RUCO and other intervenors filed their surrebuttal testimony with the ACC. The ACC Staff adjusted their initial recommendations to, among other things, (i) a $281.9 million revenue increase, (ii) a 9.68% return on equity, (iii) a 0.5% fair value increment, (iv) a continuation of a 12-month post-test year plant that includes the Four Corners ELG project, and (v) support of an increase to the annual PSA increase limit to $0.006/kWh. RUCO maintained their direct position and also recommended further review of the PSA in a second phase of the 2022 Rate Case.

On August 4, 2023, APS filed rejoinder testimony addressing the ACC Staff and intervenors’ surrebuttal testimonies. APS’s rejoinder testimony included final post-Test Year Plant values, reducing the revenue requirement increase to $377.7 million from $383.1 million, which reduced the average annual customer bill impact to an increase of 11.2%. All other major provisions from APS’s rebuttal testimony were maintained in its rejoinder testimony.

APS requested that the increase become effective December 1, 2023. However, based on the current status of the proceeding, the rate effective date is currently anticipated to be in early 2024. The hearing for this rate case concluded in early October 2023. APS cannot predict the outcome of its request.

2019 Retail Rate Case

On October 31, 2019, APS filed an application with the ACC for an annual increase in retail base rates (the "2019 Rate Case"). On August 2, 2021, an Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021.

The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners Power Plant ("Four Corners") selective catalytic reduction ("SCR") project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of the Navajo Generating Station (the "Navajo Plant") regulatory asset recovery related to the closure of the Navajo Plant (see "Navajo Plant" below), (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan related to the closure or future closure of coal-fired generation facilities include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant ("Cholla"), and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the Arizona Renewable Energy Standard and Tariff ("RES") adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, which includes a 20-basis point penalty, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation, and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, resulted in a total annual revenue decrease for APS of $4.8 million, excluding temporary payments and expenditures, under the CCT plan. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. In addition, the ACC ordered extensive compliance and reporting obligations. APS completed the implementation of the new on-peak hours for residential customers before the September 1, 2022 deadline.

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Additionally, consistent with the 2019 Rate Case decision, as of September 2023, APS completed the following payments that will be recoverable through rates related to the CCT: (i) $6.66 million to the Navajo Nation; (ii) $0.5 million to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) $1 million to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County communities for CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The ACC has also authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. Expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations is contingent upon completion of a census of the unelectrified homes and businesses in each that are also within APS service territory. The census work was completed in November 2022 and disbursement of the $1.25 million for electrification of homes and businesses is planned to be finalized after discussions with the Navajo Nation and the Hopi Tribe are completed.

On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215.5 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20-basis-point penalty reduction to the return on equity, among other things. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The Arizona Court of Appeals heard oral arguments on November 30, 2022. On March 6, 2023, the Court issued its opinion in this matter, affirming in part and reversing in part the ACC's decision in the 2019 Rate Case. The Court vacated the 20-basis-point penalty included in the ACC's allowed return on equity, as the Court determined the use of customer service metrics to justify the reduction exceeded the ACC's ratemaking authority. Additionally, the Court vacated the disallowance of $215.5 million of APS's Four Corners SCR investment. The Court remanded the issue to the ACC for further proceedings. The ACC requested an extension of the 30-day deadline to appeal the matter to the Arizona Supreme Court, and the Arizona Supreme Court granted the extension of the deadline to May 8, 2023. The ACC filed an appeal on May 8, 2023, and on May 15, 2023, requested a suspension of the case to allow for settlement discussions between the parties, which was approved by the Court.

On June 14, 2023, APS and the ACC Legal Division filed a joint resolution with the ACC to allow recovery of the $215.5 million in costs related to the installation of the Four Corners SCR, a reversal of the 20-basis point reduction to APS's return on equity from 8.9% to 8.7% as a result of the 2019 Rate Case Decision, and recovery of $59.6 million in revenue lost by APS between December of 2021 and June 20, 2023. On June 21, 2023, the ACC approved the joint resolution and proposals therein for recovery through the Court Resolution Surcharge ("CRS") mechanism, which became effective on July 1, 2023. As of September 30, 2023, $6.4 million of the $59.6 million historical portion of the CRS has been collected. See "Court Resolution Surcharge" below for more information. On July 18, 2023, the Sierra Club filed an application for rehearing of the Commission's decision. However, the ACC did not act upon the application within 20 days, and it was therefore denied by operation of law. Subsequently, the Sierra Club did not file a notice of appeal to the Arizona Court of Appeals, and the time for an appeal has expired.

Matter of Impact of the Closures of Fossil-Based Generation Plan on Impacted Communities

On September 28, 2022, ACC Staff filed their staff report in the Matter of Impact of the Closures of Fossil-Based Generation Plan on Impacted Communities. APS and other interested parties filed comments on the report. On October 21, 2022, ACC Staff filed a revised report and proposed order. The revised report and proposed order recommended that funds for CCT shall not be collected from rate payers. On December 8, 2022, the ACC voted against ACC Staff's proposed order, and on April 17, 2023, the ACC closed the docket. Any further action on CCT issues will take place in utility rate cases, including the currently pending 2022 Rate Case.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. APS cannot predict the outcome of this matter.

2016 Retail Rate Case Filing and the 2017 Settlement Agreement

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for, among other things, a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications, and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"). The new rates went into effect on August 19, 2017.

See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms. See "2022 Retail Rate Case" above for proposed modifications of adjustment mechanisms in the 2022 Rate Case.

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 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supported existing approved projects and commitments and requested a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic. The APS Solar Communities program was originally a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned distributed renewable energy ("DG") systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the REAC to support APS's RES programs.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its IRP, and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source requests for proposals ("RFP") requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget included funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the continuation of the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS's budget proposal supported existing approved projects and commitments and requests a waiver of the RES residential and non-residential distributed energy requirements for 2022. On May 18, 2022, the ACC approved the 2022 RES Implementation Plan, including an amendment requiring a stakeholder working group convene to develop a community solar program for the Commission's consideration at a future date. On September 23, 2022, APS filed a community solar proposal in compliance with the ACC order that was informed by a stakeholder working group. APS proposed a small, pilot-scale program size of up to 140 MW that would be selected through a competitive RFP. The ACC has not yet ruled on the proposal. However, on November 10, 2022, the ACC approved a bifurcated community solar process, directing ACC Staff to develop a statewide policy through additional stakeholder involvement and establishing a separate evidentiary hearing to define other policy components. On March 23, 2023, the ACC approved a policy statement that included information on how statewide community solar and storage programs should be structured, their location, and inclusion in RFPs. The remainder of the community solar program policy components were deferred to the ACC's Hearing Division so that a formal evidentiary hearing could be held to consider issues of substance related to community solar. APS cannot predict the outcomes of these future activities.

On July 1, 2022, APS filed its 2023 RES Implementation Plan and proposed a budget of approximately $86.2 million, excluding any funding offsets. This budget contained funding for programs to comply with Commission-approved initiatives, including the 2019 Rate Case decision. APS's budget proposal supported existing approved projects and commitments and requested a waiver of the RES residential and non-residential distributed energy requirements for 2022. On November 10, 2022, the ACC approved the 2023 RES Implementation Plan, including APS's requested waiver of the distributed energy requirement for 2023.

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On June 30, 2023, APS filed its 2024 RES Implementation Plan and proposed a budget of approximately $95.1 million. APS's budget proposal supports existing approved projects and commitments and requests a waiver of the RES renewable energy credit requirements to demonstrate compliance with the Annual Renewable Energy Requirement for 2023. The ACC has not yet ruled on the 2024 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan annually for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its LFCR mechanism. See below for discussion of the LFCR.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption, which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Implementation Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Implementation Plan that proposed an additional one-time incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Implementation Plan.

On December 17, 2021, APS filed its 2022 DSM Implementation Plan in accordance with an extension granted in 2021. The 2022 DSM Plan requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021. On November 10, 2022, the ACC approved the 2022 DSM Implementation Plan, including a proposed performance incentive.

On November 30, 2022, APS filed its 2023 DSM Implementation Plan, which requested a budget of $88 million. On May 31, 2023, APS filed an amended 2023 DSM Implementation Plan. The amended plan maintains the originally proposed budget of $88 million. The ACC has not yet ruled on the 2023 DSM Implementation Plan.

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In accordance with an extension granted by the ACC, APS intends to file its 2024 DSM Implementation Plan by November 30, 2023.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
- an adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- the PSA rate includes (a) a "forward component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "historical component," under which differences between actual fuel and purchased power costs and those recovered or refunded through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "transition component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and
- the PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2023 and 2022 (dollars in thousands):

	Nine Months Ended September 30,	
	2023	2022
Beginning balance	$ 460,561	$ 388,148
Deferred fuel and purchased power costs — current period	486,382	228,483
Amounts charged to customers	(420,277)	(171,606)
Ending balance	$ 526,666	$ 445,025

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate was a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which was reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the rate increase taking effect in April 2021, and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a rate of $0.003544 per kWh and consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit to better understand the factors that contributed to the increase in fuel costs.

On April 1, 2022, the ACC filed a final report of its third-party audit findings regarding APS's fuel and purchased power costs for the period January 2019 through January 2021. The report contains an in-depth review of APS's fuel and purchased power contracts, its monthly fuel accounting activities, its forecasting and dispatching procedures, and its monthly PSA filings, among other fuel-related activities. The report finds that APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity are reasonable and appropriate. The report includes several recommendations for the ACC's consideration, including review of current contracts, maintenance schedules, and certain changes and improvements to the schedules in APS's monthly PSA filings. On December 27, 2022, ACC Staff filed a proposed order supporting adoption of the recommendations in the third-party audit report, and the ACC approved the proposed order on February 22, 2023.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate was a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022.

On November 30, 2022, APS filed its PSA rate for the PSA year beginning February 1, 2023. To address the growing under-collected PSA balance, APS also requested that one of three different options be adopted, including a temporary or permanent increase of the annual cap to $0.006 per kWh. On February 23, 2023, the ACC approved an overall PSA rate of $0.019074 per kWh, which consisted of a forward component of $(0.005527) per kWh, a historical component of $0.013071 per kWh and a transition component of $0.011530 per kWh, that will continue until further notice of the ACC. The rate became effective with the first billing cycle in March 2023 and is designed to bring the PSA balancing account to near-zero over a 24-month period. APS is also required to notify the ACC when the PSA balancing account approaches $0.5 million. In its 2022 Rate Case, APS proposed a permanent increase in the annual PSA adjustor rate cap, which would increase the amount the rate can change in any given year from the currently effective $0.004 per kWh to $0.006 per kWh. The ACC has not yet ruled on this application and APS cannot predict the outcome of this matter.

In accordance with the PSA Plan of Administration, APS is required to seek ACC approval to recover costs related to third-party energy storage systems through its PSA adjustment mechanism. To date in 2023, APS has executed nine energy storage PPAs whose costs have been approved for recovery through the PSA. APS executed one energy storage PPA in 2022 that was approved for cost-recovery through the PSA and four in 2021, excluding one energy storage PPA that was approved but later terminated by APS due to project delays.

Environmental Improvement Surcharge. The EIS permits APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. The EIS includes an overall cap of $0.0005 per kWh (approximately $13 million to $15 million per year). APS's February 1, 2023 application requested an increase in the charge to $14.7 million, or $3.3 million over the prior-period charge. On March 10, 2023, APS filed an amended application requesting an EIS charge of $4.0 million, a decrease of $10.7 million from the February EIS request and a decrease of $7.5 million from the prior-period charge. The revised 2023 EIS became effective with the first billing cycle in April 2023. APS has proposed eliminating the EIS in its 2022 Rate Case application. The ACC has not yet ruled on this application, and APS cannot predict the outcome of this matter.

Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow 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 settlement agreement entered into in 2012 regarding APS's rate case ("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. 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 with 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. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 17, 2020, APS submitted a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Cuts and Job Act (the "Tax Act"), as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020 filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Effective June 1, 2022, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $33 million for the 12-month period beginning June 1, 2022, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $6.4 million and retail customer rates would have decreased by approximately $26.6 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $2.4 million, resulting in a reduction to the residential rate and increases to commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2022.

Effective June 1, 2023, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $34.7 million for the 12-month period beginning June 1, 2023, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $20.7 million and retail customer rates would have increased by approximately $14 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $10 million, resulting in reductions to the residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2023.

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 DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.50 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential kWh and 2.68 cents for lost non-residential kWh as set forth in the 2019 Rate Case decision. The adjustment to the LFCR 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 kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment; thus, the previously approved rates continued to remain intact and the $11.8 million increase was reflected in APS's 2022 filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism, as a result of the 2019 Rate Case decision effective on December 1, 2021, did not materially impact its results of operations and financial statements for the year ended December 31, 2021. However, as a result of certain changes made to the LFCR mechanism in the 2019 Rate Case decision, the mechanism no longer qualified for alternative revenue program accounting treatment, which impacts the future timing of related revenue recognition.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels, which was inclusive of the $11.8 million balance from the 2021 filing). On May 9, 2022, the ACC Staff filed its revised report and proposed order regarding APS's 2022 LFCR adjustment, concluding that APS calculated the adjustment in accordance with its Plan of Administration. On May 18, 2022, the ACC approved the 2022 LFCR adjustment, with a rate effective date of June 1, 2022.

On February 15, 2023, APS filed a letter to the ACC docket stating that, in accordance with Decision No. 78585, APS and ACC Staff have agreed to move the filing date for the annual LFCR adjustment to July 31 each year. On July 31, 2023, APS filed its 2023 annual LFCR adjustment, requesting that the annual LFCR recovery amount be increased to $68.7 million (a $9.6 million increase from previous levels). The ACC has not yet ruled on this application.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 were recorded as a part of the balancing account and were addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit were recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which provided an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit were recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021, and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in a subsequent APS rate case.

Court Resolution Surcharge. The CRS mechanism permits APS to recover certain costs associated with investments and expenses for APS's purchase and installation of SCR technology for Four Corners Units 4 and 5 and a change in APS's allowable return on equity as required by the Arizona Court of Appeals and approved by the ACC in Decision No. 78979. The CRS went into effect on July 1, 2023 at a rate of $0.00175 per kWh. The rate is designed to recover $59.6 million in revenue lost by APS between December of 2021 and June 20, 2023, and the prospective recovery of ongoing costs related to the SCR investments and expense and the allowable return on equity difference in current base rates. The current CRS will be recalculated at the end of the 2022 Rate Case to remove the effects of the prospective recovery related to the allowable return on equity difference. The portion of the CRS representing the recovery of the $59.6 million of lost revenue between December of 2021 and June 20, 2023, $6.4 million of which has been collected as of September 30, 2023, will cease upon full collection of the lost revenue. Finally, recovery of ongoing costs related to the SCR investments will continue until the Company's next rate case in which they can be incorporated therein. See "2019 Retail Rate Case" above for more information.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from residential DG solar facilities will be determined using a Resource Comparison Proxy ("RCP") methodology as determined in the ACC's generic Value and Cost of Distributed Generation docket. RCP is a method that is based on the most recent five-year rolling average price that APS incurs for utility-scale solar photovoltaic projects. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. The ACC is no longer pursuing development of a forecasted avoided cost methodology as an option for utilities in place of the RCP. Commercial customers, grandfathered residential solar customers, and residential customers with DG systems other than solar facilities continue to qualify for net metering.

In addition, the ACC made the following determinations in the Value and Cost of Distributed Generation docket:

- RCP customers who have interconnected a DG system or submitted an application for interconnection for DG systems will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility (for APS residential customers, as of September 1, 2017, based on APS's 2017 Rate Case Decision);
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an initial export price is set for utilities, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

On October 11, 2023, the ACC voted to open a new general docket to hold a hearing to explore potential future changes to the 10% annual reduction cap in the solar export rate paid by utilities to distributed solar customers for exports to the grid and the 10-year rate lock period for those customers that were approved in the ACC's Value and Cost of Distributed Generation Docket. A procedural conference was held on November 1, 2023 to discuss the process going forward. The amounts the Company pays customers for solar exports under its RCP rate rider could be affected by this docket. APS cannot predict the outcome of this matter.

In accordance with the 2017 Rate Case Decision, APS filed its request for a RCP export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021. On April 29, 2022, APS filed an application to decrease the RCP price to

8.46 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2022. On July 12, 2022, the ACC approved the RCP as filed.

On May 1, 2023, APS filed an application for revisions to the RCP. This application would decrease the RCP price to 7.619 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2023. On August 25, 2023, the ACC approved the RCP as filed.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources. Draft energy rules were subsequently issued and a series of revisions were made to the draft rules in 2019 and 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new Energy Efficiency Standard ("EES") was not included in the proposed rules.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted revised clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. During the August 2022 Open Meeting, Commissioners voted to postpone a decision on the all-source RFP and IRP rulemaking package until 2023. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop triennial 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In February 2022, the ACC acknowledged APS's 2020 IRP filed on June 26, 2020. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by January 1, 2030.

On May 1, 2023, APS, Tucson Electric Power Company, and UNS Electric, Inc. filed a joint request for an extension to file the IRPs from August 1, 2023 to November 1, 2023. On June 21, 2023, the ACC granted the extension. As a result, APS filed its 2023 IRP on November 1, 2023. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Equity Infusions

On October 27, 2023, APS filed a notice of intent to increase Pinnacle West's equity in APS in 2024. APS is currently authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking Commission approval. APS seeks approval under Arizona Administrative Code provision R14-2-803 to receive from Pinnacle West in 2024 up to $500 million in additional equity infusions above the currently authorized limit of $150 million annually. APS cannot predict the outcome of this application.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year PPAs with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements. On July 19, 2023, the agreements for these two PPAs were terminated due to project delays.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. The new rules became effective on April 18, 2022.

In accordance with the ACC service disconnection rules, APS now uses the calendar-based method to suspend the disconnection of customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). Customers with past due balances of $75 or greater as of the end of the Annual Disconnection Moratorium are automatically placed on six-month payment arrangements. In addition, APS voluntarily began waiving late payment fees of its customers ("Late Fee Waivers") on March 13, 2020. Effective February 1, 2023, late payment fees for residential customers were reinstated. Late payment fees for commercial and industrial customers were reinstated effective May 1, 2022. Since the suspensions and moratoriums on disconnections began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed and the Governor signed a bill that repealed the electric deregulation law that had been in place in Arizona since 1998. APS cannot predict what impact, if any, this change will have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates of convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law. As the ACC's questions pertained to the retail competition law subsequently repealed in April 2022, the Attorney General has not responded to the ACC's request and the questions are now moot. No action has been taken by the ACC regarding this application since that time. However, on May 17, 2023, the Retail Energy Supply Association filed a motion with the ACC requesting it to re-open the generic docket to re-examine the ACC's electric competition rules. No action has been taken by the ACC regarding this motion. APS cannot predict the outcome of these matters.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200 to 300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. The Arizona Court of Appeals heard oral arguments on November 30, 2022. On March 6, 2023, the Court of Appeals issued its order in the matter, vacating the ACC's disallowance of the SCR investment and remanding the matter back to the ACC for further review in accordance with ACC rules and the order of the Court of Appeals. On June 21, 2023, the ACC approved a joint settlement filed by APS and the ACC's Legal Division that resolved all issues relating to the 2019 Rate Case decision, including recovery of the cost of the Four Corners SCRs. See above for further discussion on the 2019 Rate Case decision.

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") approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS is required to cease burning coal at its remaining Cholla units by April 2025.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $33.8 million as of September 30, 2023, 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. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant, $45.4 million as of September 30, 2023, in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset, $11.6 million as of September 30, 2023. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

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

	Amortization Through	September 30, 2023	December 31, 2022
Pension	(a)	$ 631,307	$ 637,656
Deferred fuel and purchased power (b) (c)	2024	526,666	460,561
Income taxes — allowance for funds used during construction ("AFUDC") equity	2053	188,845	179,631
Ocotillo deferral (e)	2031	131,013	138,143
SCR deferral (e)(f)	2031	91,514	97,624
Retired power plant costs	2033	87,325	98,692
Lease incentives	(h)	39,700	—
Deferred property taxes	2027	34,630	41,057
Deferred compensation	2036	34,492	33,660
Deferred fuel and purchased power — mark-to-market (Note 7)	2026	34,131	—
Income taxes — investment tax credit basis adjustment	2056	33,684	23,977
Palo Verde VIEs (Note 6)	2046	20,812	20,933
Active Union Medical Trust	(g)	17,759	18,226
Power supply adjustor - interest	2024	13,899	1,541
Navajo coal reclamation	2026	11,628	13,862
Four Corners cost deferral	2024	9,941	15,999
Mead-Phoenix transmission line contributions in aid of construction ("CIAC")	2050	8,799	9,048
Loss on reacquired debt	2038	8,305	9,468
Tax expense adjustor mechanism (b)	2031	5,354	5,845
Lost fixed cost recovery (b)	2023	—	9,547
Other	Various	3,759	6,630
Total regulatory assets (d)		$ 1,933,563	$ 1,822,100
Less: current regulatory assets		$ 630,319	$ 538,879
Total non-current regulatory assets		$ 1,303,244	$ 1,283,221

(a) This asset represents the future recovery of pension benefit obligations and expense through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. As a result of the 2019 Rate Case Decision, the amount authorized for inclusion in rate base was determined using an averaging methodology, which resulted in a reduced return in retail rates. See Note 5 for further discussion.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(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."
(e) Balance includes amounts for future regulatory consideration and amortization period determination.
(f) See "Four Corners SCR Cost Recovery" discussion above.
(g) Collected in retail rates.
(h) Amortization periods vary based on specific terms of lease contract. See Note 14.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Amortization Through	September 30, 2023	December 31, 2022
Excess deferred income taxes — ACC - Tax Act (a)	2046	$ 929,420	$ 971,545
Excess deferred income taxes — FERC - Tax Act (a)	2058	214,499	221,877
Asset retirement obligations	2057	343,998	354,002
Other postretirement benefits	(d)	234,832	270,604
Removal costs	(c)	96,698	106,889
Income taxes — deferred investment tax credit	2056	67,440	48,035
Income taxes — change in rates	2051	61,879	64,806
Four Corners coal reclamation	2038	54,275	52,592
Renewable energy standard (b)	2024	37,624	35,720
Spent nuclear fuel	2027	33,616	39,217
Demand side management (b)	2023	23,706	8,461
Sundance maintenance	2031	19,215	16,893
Property tax deferral (e)	2024	12,018	15,521
FERC transmission true up (b)	2025	6,087	22,895
Tax expense adjustor mechanism (b) (e)	N/A	4,835	4,835
Deferred fuel and purchased power — mark-to-market (Note 7)	2026	—	96,367
Other	Various	6,128	3,092
Total regulatory liabilities		$ 2,146,270	$ 2,333,351
Less: current regulatory liabilities		$ 226,989	$ 271,575
Total non-current regulatory liabilities		$ 1,919,281	$ 2,061,776

(a) For purposes of presentation on the Statement of Cash Flows, amortization of the regulatory liabilities for excess deferred income taxes are reflected as “Deferred income taxes” under Cash Flows From Operating Activities.
(b) See “Cost Recovery Mechanisms” discussion above.
(c) In accordance with regulatory accounting guidance, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(d) See Note 5.
(e) Balance includes amounts for future regulatory consideration and amortization period determination.

5. 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 other postretirement benefit plans for the employees of Pinnacle West and our subsidiaries. The other postretirement benefit plans include a group life and medical plan and a post-65 retiree health reimbursement arrangement (“HRA”). Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Pension Benefits				Other Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022	2023	2022	2023	2022
Service cost — benefits earned during the period	$ 9,865	$ 13,868	$ 29,595	$ 41,605	$ 2,142	$ 4,117	$ 6,426	$ 12,352
Non-service costs (credits):								
Interest cost on benefit obligation	38,390	26,873	115,170	80,619	5,627	4,372	16,882	13,118
Expected return on plan assets	(45,735)	(46,443)	(137,204)	(139,331)	(10,872)	(11,510)	(32,616)	(34,531)
Amortization of:								
Prior service credit	—	—	—	—	(9,447)	(9,447)	(28,341)	(28,341)
Net actuarial loss/(gain)	9,605	4,379	28,815	13,136	(2,404)	(3,209)	(7,211)	(9,627)
Net periodic cost/(benefit)	$ 12,125	$ (1,323)	$ 36,376	$ (3,971)	$ (14,954)	$ (15,677)	$ (44,860)	$ (47,029)
Portion of cost/(benefit) charged to expense	$ 6,828	$ (4,246)	$ 20,568	$ (12,258)	$ (10,851)	$ (11,318)	$ (32,536)	$ (33,736)

Contributions

We have not made any voluntary contributions to our pension plan year-to-date in 2023. The minimum required contributions for the pension plan are zero for the next three years and we do not expect to make any contributions in 2023, 2024 or 2025. With regard to contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2023 and do not expect to make any contributions in 2023, 2024 or 2025.

6. 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 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2023 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

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

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income for the three and nine months ended September 30, 2023, of $4 million and $13 million respectively, and for the three and nine months ended September 30, 2022 of $4 million and $13 million, respectively. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Our Condensed Consolidated Balance Sheets at September 30, 2023, and December 31, 2022, include the following amounts relating to the VIEs (dollars in thousands):

	September 30, 2023	December 31, 2022
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$ 87,394	$ 90,296
Equity — Noncontrolling interests	113,520	111,229

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

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the Nuclear Regulatory Commission ("NRC") issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $324 million beginning in 2023, and up to $501 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.

7. Derivative Accounting

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

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheets as an asset or liability and are measured at fair value. See Note 11 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 the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Energy Derivatives

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 energy derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate. See Note 4. Gains and losses from energy derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

The following table shows the outstanding gross notional volume of energy derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	**Unit of Measure**	**September 30, 2023**	**December 31, 2022**
Power	GWh	390	1,197
Gas	Billion cubic feet	198	149

Gains and Losses from Energy Derivative Instruments

For the three and nine months ended September 30, 2023 and 2022, APS had no energy derivative instruments in designated accounting hedging relationships.

The following table provides information about gains and losses from energy derivative instruments not designated as accounting hedging instruments (dollars in thousands):

		Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts	**Financial Statement Location**	**2023**	**2022**	**2023**	**2022**
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ (32,096)	$ 138,855	$ (271,171)	$ 425,122

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

Energy Derivative Instruments in the Condensed Consolidated Balance Sheets

Our energy 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 energy derivative contracts with the counterparty's non-current energy derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

As of September 30, 2023: (dollars in thousands)	**Gross Recognized Derivatives (a)**	**Amounts Offset (b)**	**Net Recognized Derivatives**	**Other (c)**	**Amount Reported on Balance Sheets**
Current assets	$ 21,754	$ (10,383)	$ 11,371	$ 5	$ 11,376
Investments and other assets	6,695	(3,524)	3,171	—	3,171
Total assets	28,449	(13,907)	14,542	5	14,547
Current liabilities	(46,044)	10,383	(35,661)	(7,071)	(42,732)
Deferred credits and other	(16,536)	3,524	(13,012)	—	(13,012)
Total liabilities	(62,580)	13,907	(48,673)	(7,071)	(55,744)
Total	$ (34,131)	$ —	$ (34,131)	$ (7,066)	$ (41,197)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $7,071 thousand and cash margin provided to counterparties of $5 thousand.

As of December 31, 2022: (dollars in thousands)	**Gross Recognized Derivatives (a)**	**Amounts Offset (b)**	**Net Recognized Derivatives**	**Other (c)**	**Amount Reported on Balance Sheets**
Current assets	$ 103,484	$ (15,808)	$ 87,676	$ 28	$ 87,704
Investments and other assets	49,777	(5,383)	44,394	—	44,394
Total assets	153,261	(21,191)	132,070	28	132,098
Current liabilities	(47,670)	15,808	(31,862)	(5,835)	(37,697)
Deferred credits and other	(9,223)	5,383	(3,840)	—	(3,840)
Total liabilities	(56,893)	21,191	(35,702)	(5,835)	(41,537)
Total	$ 96,368	$ —	$ 96,368	$ (5,807)	$ 90,561

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $5,835 thousand and cash margin provided to counterparties of $28 thousand.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Interest Rate Derivatives

On October 19, 2022, Bright Canyon Energy entered into an interest rate swap to hedge the variable interest rate exposure relating to the credit agreement for the Los Alamitos project. The transaction qualified and had been designated as a cash flow hedge. The interest rate swap was included in the BCE Sale and was transferred to Ameresco as part of the BCE Sale closing. See Note 16. Prior to being transferred to Ameresco, the interest rate swap was in an asset position valued at $0.2 million. As of September 30, 2023, the interest rate swap has no impact on our Condensed Consolidated Balance Sheets.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of September 30, 2023, we have one counterparty for which our exposure represents approximately 29% of Pinnacle West's $15 million of risk management assets. This exposure relates to a master agreement with the counterparty, and the counterparty is rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our energy 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 energy derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	September 30, 2023
Aggregate fair value of derivative instruments in a net liability position	$ 62,579
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	47,355

(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 have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could require us to post additional collateral of approximately $161 million if our debt credit ratings were to fall below investment grade.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

8. Commitments and Contingencies

Palo Verde 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 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, 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, which required DOE to pay the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007, through June 30, 2011. In addition, the settlement agreement provided APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2025.

APS has submitted nine claims pursuant to the terms of the August 18, 2014 settlement agreement, for nine separate time periods during July 1, 2011 through June 30, 2022. The DOE has approved and paid $138.2 million for these claims (APS's share is $40.2 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 4. On October 31, 2023, APS filed its tenth claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $18.5 million (APS's share is $5.4 million).

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. This insurance limit is subject to an adjustment every five years based upon the aggregate percentage change in the Consumer Price Index. The most recent adjustment took effect on October 5, 2023. As of that date, in accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $16.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers. The remaining balance of approximately $16.1 billion of liability coverage is provided through a mandatory, industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $165.9 million, subject to a maximum annual premium of approximately $24.7 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $144.9 million, with a maximum annual retrospective premium of approximately $21.6 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $22.4 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. Additionally, at the sole discretion of the NEIL Board of Directors, APS would be liable to provide approximately $62.6 million in deposit premium within 20 days of request as assurance to satisfy any site obligation of retrospective premium assessment. The insurance coverage discussed in this, and the previous paragraph, is subject to certain policy conditions, sublimits, and exclusions.

Contractual Obligations

As of September 30, 2023, our fuel and purchased power and purchase obligation commitments have increased by $6.8 billion from the information provided in our 2022 Form 10-K. The change is primarily due to new purchased power and energy storage commitments and also includes a $505 million reduction of commitments due to the termination of an energy storage purchased power contract for a project that was not developed. The majority of the changes relate to 2025 and thereafter. This amount includes approximately $5.3 billion of commitments relating to purchased power lease contracts. See Note 14.

Other than the items described above, there have been no material changes, as of September 30, 2023, outside the normal course of business in contractual obligations from the information provided in our 2022 Form 10-K. See Note 3 for discussion regarding changes in our short-term and long-term debt obligations.

Superfund and Other Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). The RI/FS for OU3 was finalized and submitted to EPA at the end of 2022. APS cannot predict the EPA's timing with respect to this matter. APS's estimated costs related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the ultimate remediation requirements are not yet finalized by EPA, at the present time expenditures related to this matter cannot be reasonably estimated.

In connection with APS's status as a PRP for OU3, since 2013 APS and at least two dozen other parties have been defendants in various CERCLA lawsuits stemming from allegations that contamination from OU3 and elsewhere has impacted groundwater wells operated by the Roosevelt Irrigation District ("RID"). At this time, only one active lawsuit remains pending, which is on appeal to the U.S. Court of Appeals for the Ninth Circuit based on a U.S. District Court order dismissing cost recovery claims of approximately $20.7 million by a service provider for RID. APS is unable to predict the outcome of any further litigation related to this claim or APS's share of liability related to that claim; however, APS does not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

In addition, as part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the 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. Since that time, ADEQ has taken no action based on the information provided by APS.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing per-and polyfluoroalkyl ("PFAS") compounds at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform the Company that it would be commencing on-site investigations within the SIBW site, including the Ocotillo power plant, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. APS estimates that its costs to oversee and participate in the remedial investigation work will be approximately $1.7 million. At the present time, we are unable to predict the outcome of this matter and any further expenditures related to necessary remediation, if any, or further investigations cannot be reasonably estimated.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. The Arizona Court of Appeals heard oral arguments on November 30, 2022. On March 6, 2023, the Court of Appeals issued its order in the matter, vacating the ACC's disallowance of the SCR investment and remanding the matter back to the ACC for further review in accordance with ACC rules and the order of the Court of Appeals. On June 21, 2023, the ACC approved a joint settlement filed by APS and the ACC's Legal Division that resolved all issues relating to the 2019 Rate Case decision, including recovery of the cost of the Four Corners SCRs. See Note 4 for additional information regarding the Four Corners SCR cost recovery and the 2019 Rate Case.

Environmental Matters

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

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.

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These criteria include standards governing 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 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. Such closure requirements are deemed “forced closure” or “closure for cause” of unlined surface impoundments and are the subject of the regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, and new state legislation has been adopted providing ADEQ with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits, which would impact facilities like Four Corners located on the Navajo Nation. The proposal remains pending.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- With respect to APS’s Cholla facility, APS’s application for alternative closure was submitted to EPA on November 30, 2020. While EPA has deemed APS’s application administratively “complete,” the Agency’s approval remains pending. If granted, this application would allow the continued disposal of CCR within Cholla’s existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This application will be subject to public comment and, potentially, judicial review. We expect to have a proposed decision from EPA regarding Cholla sometime in 2023.

- On May 18, 2023, EPA published a proposal that expands the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. EPA proposes to define a new class of CCR management units (“CCRMUs”) that broadly encompass any location at an operating coal-fired power plant where CCR would have been placed on land. As proposed, this would include not only historically closed landfills and surface impoundments but also prior applications of CCR beneficial use. EPA expects to finalize this proposal by spring of 2024.

We cannot at this time predict the outcome of these regulatory proceedings or when EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS’s management of CCR could materially increase, which could affect APS’s financial position, results of operations, or cash flows.

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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 $25 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $19 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. As to Cholla, APS currently estimates that its share of corrective action and monitoring costs at this facility will likely range from $35 million to $40 million, which similarly would be incurred over 30 years. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment and final remedy selection process, APS cannot predict any ultimate impacts to APS; however, at this time APS does not believe that any potential changes to the cost estimate for Four Corners or Cholla would have a material impact on its financial position, results of operations or cash flows.

EPA Power Plant Carbon Regulations. EPA's regulation of carbon dioxide emissions from electric utility power plants has proceeded in fits and starts over most of the last decade. Starting on August 3, 2015, EPA finalized the Clean Power Plan, which was the Agency's first effort at such regulation through system-wide generation dispatch shifting. Those regulations were subsequently repealed by the EPA on June 19, 2019 and replaced by the Affordable Clean Energy ("ACE") regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the ACE regulations on January 19, 2021, and ordered a remand for EPA to develop replacement regulations consistent with the original 2015 Clean Power Plan, the U.S. Supreme Court subsequently reversed that decision on June 30, 2022, holding that the Clean Power Plan exceeded EPA's authority under the Clean Air Act.

In the latest set of proposed rules, released on May 23, 2023, EPA contemplates emission standards and guidelines for various subcategories of new and existing power plants. Unlike EPA's Clean Power Plan regulations from 2015, which took a broad, system-wide approach to regulating carbon emissions from electric utility fossil-fuel burning power plants, the most recent proposal is limited to measures that can be installed at individual power plants to limit planet-warming emissions.

As such, for new natural gas-fired combustion turbine power plants, EPA is proposing that carbon emission performance standards apply based on the annual capacity factors. For the highest utilization combustion turbines, EPA is therefore proposing that such facilities be retrofitted for carbon capture and sequestration or utilization controls ("CCS") or varying levels of hydrogen gas ("H2") co-firing. As for existing natural gas-fired combustion turbines, EPA is imposing similar control requirements at large, high utilization generating units, but is otherwise not proceeding at this time with further regulation. As such, under EPA's proposal, this means that both new and existing peaking gas-fired combustion turbines (i.e., those with a 20% or less annual capacity factor) are effectively unregulated under the proposed regulations.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has developed subcategories based on planned retirement dates. This means that facilities retiring between 2030 and before 2040 must meet increasingly stringent emission limits up to natural-gas co-firing starting in 2030. However, for those facilities with no planned retirement date prior to 2040, EPA is requiring those plants to be retrofitted with CCS controls by 2030.

EPA expects to take final action on this proposal by spring or summer of 2024. At this time, APS cannot predict the outcome of this rulemaking or when EPA will take final action. In addition, APS is continuing to evaluate this proposal and its potential impact on APS's operations. Depending on the eventual outcome, the costs associated with APS's operation of its current and future thermal power plants could materially increase, which could affect APS's financial position, results of operations, or cash flows.

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 APS's fossil-fuel powered 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.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019 filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. The EAB denied the environmental group petition on September 30, 2020. While on January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit, the parties to the litigation (including APS) finalized a settlement on May 2, 2022. This settlement requires investigation of thermal wastewater discharges from Four Corners, administratively closes the litigation filed in January of 2021, and is not expected to have a material impact on APS's financial position, results of operations, or cash flows.

Four Corners — 4CA Matter

On July 6, 2016, 4CA purchased El Paso's 7% interest in Four Corners. NTEC purchased this 7% interest on July 3, 2018, from 4CA. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and paid 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note, which was paid in full as of June 30, 2022.

In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West Wind Projects

In October 2023, the Tenaska wind farm investments were reorganized such that they are no longer held by BCE, rather they are now held under the new Pinnacle West subsidiary, PNW Power. See Notes 1 and 16 for more information.

Tenaska Clear Creek Wind, LLC, the developer, owner, and operator of the Clear Creek wind farm, has disputed the proposed cost allocation of system upgrades related to connecting the Clear Creek wind farm to the transmission system and filed a complaint with FERC on May 21, 2021, which was granted in part and denied in part on December 16, 2021. Tenaska Clear Creek Wind, LLC filed a request for rehearing, which was denied on September 9, 2022. Subsequently, Tenaska Clear Creek Wind, LLC filed with FERC a request for rehearing and a motion for stay of the September 9, 2022 order. FERC denied the request for rehearing and the motion for stay with substantive discussion in an order issued on February 16, 2023. Tenaska Clear Creek Wind, LLC, has filed Petitions for Review of the relevant orders with the U.S. Court of Appeals for the D.C. Circuit, which are still pending. Tenaska Clear Creek Wind, LLC filed its opening brief on June 30, 2023.

Tenaska Clear Creek Wind, LLC filed a second complaint with FERC on May 25, 2022, alleging that the wind farm was being curtailed in a discriminatory manner. The May 25, 2022 Complaint was denied by FERC on December 15, 2022, and Tenaska Clear Creek Wind, LLC requested rehearing of the denial on January 13, 2023. The request for rehearing was denied by FERC with substantive discussion in an order issued on April 20, 2023. Tenaska Clear Creek Wind, LLC has filed Petitions for Review of the relevant orders with the U.S. Court of Appeals for the D.C. Circuit, which are still pending.

Due to the disputed system upgrades and the related curtailment, the Clear Creek wind farm has experienced a significant reduction in power generation that has had a material adverse impact on the project's ability to generate cash flow for investors. These energy curtailments are expected to persist, unless and until system upgrades are implemented to alleviate the present transmission system congestion, or the disputes are determined in favor of, or settled in a manner favorable to, Tenaska Clear Creek Wind, LLC. As such, during the fourth quarter of 2022, due to these ongoing disputes, cost allocation uncertainties, and no probable favorable resolution, BCE determined its equity method investment was fully impaired. Prior to the impairment, the investment had a carrying value of $17.1 million, which has been written-down to reflect the investment's estimated fair value of zero, as of December 31, 2022. Pinnacle West's Consolidated Statement of Income for the year ended December 31, 2022 included an after-tax loss of $12.8 million relating to this impairment.

BCE Kūpono Solar

BCE and Ameresco jointly own a special purpose entity that is sponsoring the Kūpono Solar project. This project is a 42 MW solar and battery storage facility in O'ahu, Hawaii that will supply clean renewable energy and capacity under a 20-year power purchase agreement with Hawaiian Electric Company, Inc. The Kūpono Solar project is expected to be completed in 2024. On April 18, 2023, the Kūpono Solar special purpose entity entered into a $140 million non-recourse construction financing agreement. The construction financing will convert into a sale leaseback agreement upon commercial operation of the project. As of September 30, 2023, the construction financing agreement required $40 million of sponsor equity, which has been funded by the project's equity participants and which is subject to adjustment under the construction financing agreement. In connection with the financing, Pinnacle West has issued performance guarantees relating to the project. Investments in the Kūpono Solar project are included in the BCE Sale which is expected to close by the end of 2023 or a later date as permitted by the purchase and sale agreement. See Note 16 for information relating to the BCE Sale.

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 commodity contract collateral obligations and other transactions. As of September 30, 2023, standby letters of credit totaled approximately $8 million and will expire in 2023 and 2024. As of September 30, 2023, surety bonds expiring through 2025 totaled approximately $20 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

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

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at September 30, 2023. In connection with the sale of 4CA's 7% interest to NTEC, Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. See "Four Corners — 4CA Matter" above for information related to this guarantee. Pinnacle West has not needed to perform under this guarantee. A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee, including expected credit losses, to be immaterial.

In connection with PNW Power's investments in minority ownership positions in the Clear Creek wind farm in Missouri and Nobles 2 wind farm in Minnesota, Pinnacle West has guaranteed the obligations of PNW Power to make production tax credit funding payments to borrowers of the projects (the "PTC Guarantees"). The amounts guaranteed by Pinnacle West are reduced as payments are made under the respective guarantee agreements. As of September 30, 2023, there is approximately $32 million of remaining guarantees relating to these PTC Guarantees that are expected to terminate by 2030.

On April 18, 2023, Pinnacle West issued performance guarantees in connection with BCE's Kūpono Solar project investment financing. BCE holds an equity method investment relating to the Kūpono Solar project. See discussion above and Note 16 for more information.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

9. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Other income:				
Interest income	$ 9,515	$ 1,785	$ 21,946	$ 5,118
Gain on sale of BCE (Note 16)	6,423	—	6,423	—
Miscellaneous	3	434	55	487
Total other income	$ 15,941	$ 2,219	$ 28,424	$ 5,605
Other expense:				
Non-operating costs	(3,322)	(2,956)	(9,319)	(9,110)
Investment losses — net	(870)	(935)	(2,364)	(2,191)
Miscellaneous	(2,780)	(2,854)	(4,233)	(3,450)
Total other expense	$ (6,972)	$ (6,745)	$ (15,916)	$ (14,751)

The following table provides detail of APS's other income and other expense (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Other income:				
Interest income	$ 8,717	$ 1,402	$ 19,432	$ 3,897
Miscellaneous	3	259	55	312
Total other income	$ 8,720	$ 1,661	$ 19,487	$ 4,209
Other expense:				
Non-operating costs	(3,053)	(2,369)	(8,352)	(6,407)
Miscellaneous	(580)	(654)	(2,033)	(1,250)
Total other expense	$ (3,633)	$ (3,023)	$ (10,385)	$ (7,657)

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

10. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Net income attributable to common shareholders	$ 398,214	$ 326,326	$ 501,580	$ 507,594
Weighted average common shares outstanding — basic	113,464	113,211	113,411	113,162
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	374	252	307	214
Weighted average common shares outstanding — diluted	113,838	113,463	113,718	113,376
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$ 3.51	$ 2.88	$ 4.42	$ 4.49
Net income attributable to common shareholders — diluted	$ 3.50	$ 2.88	$ 4.41	$ 4.48

11. 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 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Other significant observable inputs, including 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).

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

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs 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, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 in the 2022 Form 10-K for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Energy Derivative Instruments

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

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

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Risk Management Activities — Interest Rate Derivatives

Our interest rate derivative instruments related to a BCE interest rate swap, which was valued using financial models that utilize observable inputs for similar instruments and was classified as Level 2. The interest rate swap is no longer held as of September 30, 2023. See Note 16.

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union employee medical account. See Note 12 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury 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 fixed income 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.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts' equity security investments 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid investments are valued using active market prices.

Fair Value Tables

The following table presents the fair value at September 30, 2023, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Cash equivalents	$ 15	$ —	$ —	$ —		$ 15
Risk management activities — derivative instruments:						
Commodity contracts	—	21,623	6,825	(13,901)	(a)	14,547
Nuclear decommissioning trust:						
Equity securities	30,237	—	—	(17,110)	(b)	13,127
U.S. commingled equity funds	—	—	—	413,826	(c)	413,826
U.S. Treasury debt	273,702	—	—	—		273,702
Corporate debt	—	173,383	—	—		173,383
Mortgage-backed securities	—	181,335	—	—		181,335
Municipal bonds	—	59,553	—	—		59,553
Other fixed income	—	5,537	—	—		5,537
Subtotal nuclear decommissioning trust	303,939	419,808	—	396,716		1,120,463
Other special use funds:						
Equity securities	55,253	—	—	1,282	(b)	56,535
U.S. Treasury debt	307,710	—	—	—		307,710
Municipal bonds	—	3,914	—	—		3,914
Subtotal other special use funds	362,963	3,914	—	1,282		368,159
Total assets	$ 666,917	$ 445,345	$ 6,825	$ 384,097		$ 1,503,184
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (62,579)	$ —	$ 6,835	(a)	$ (55,744)
Total liabilities	$ —	$ (62,579)	$ —	$ 6,835		$ (55,744)

(a) Represents counterparty netting, margin, and collateral. See Note 7.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2022, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 127,129	$ 26,132	$ (21,163)	(a)	$ 132,098
Interest rate swaps	—	131	—	—		131
Subtotal risk management activities - derivative instruments	—	127,260	26,132	(21,163)		132,229
Nuclear decommissioning trust:						
Equity securities	14,658	—	—	3,827	(b)	18,485
U.S. commingled equity funds	—	—	—	472,582	(c)	472,582
U.S. Treasury debt	211,923	—	—	—		211,923
Corporate debt	—	149,226	—	—		149,226
Mortgage-backed securities	—	147,938	—	—		147,938
Municipal bonds	—	64,881	—	—		64,881
Other fixed income	—	8,375	—	—		8,375
Subtotal nuclear decommissioning trust	226,581	370,420	—	476,409		1,073,410
Other special use funds:						
Equity securities	66,974	—	—	963	(b)	67,937
U.S. Treasury debt	275,267	—	—	—		275,267
Municipal bonds	—	4,027	—	—		4,027
Subtotal other special use funds	342,241	4,027	—	963		347,231
Total assets	$ 568,822	$ 501,707	$ 26,132	$ 456,209		$ 1,552,870
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (25,874)	$ (31,020)	$ 15,357	(a)	$ (41,537)
Interest rate swaps	—	(909)	—	—		(909)
Subtotal risk management activities - derivative instruments	—	(26,783)	(31,020)	15,357		(42,446)
Total liabilities	$ —	$ (26,783)	$ (31,020)	$ 15,357		$ (42,446)

(a) Represents counterparty netting, margin, and collateral. See Note 7.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote or other characteristics of the product. 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 4.

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

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

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at September 30, 2023 and December 31, 2022:

	September 30, 2023 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average (b)**
Electricity:						
Forward Contracts (a)	$ 6,175	$ —	Discounted cash flows	Electricity forward price (per MWh)	$37.79 - $224.49	$ 121.24
Natural Gas:						
Forward Contracts (a)	650	—	Discounted cash flows	Natural gas forward price (per MMBtu)	$0.10 - $0.13	$ 0.11
Total	$ 6,825	$ —				

(a) Includes swaps and physical and financial contracts.
(b) Unobservable inputs were weighted by the relative fair value of the instrument.

	December 31, 2022 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average (b)**
Electricity:						
Forward Contracts (a)	$ 26,132	$ 1,759	Discounted cash flows	Electricity forward price (per MWh)	$37.79 - $310.69	$ 163.92
Natural Gas:						
Forward Contracts (a)	—	29,261	Discounted cash flows	Natural gas forward price (per MMBtu)	$(11.81) - $0.00	$ (5.08)
Total	$ 26,132	$ 31,020				

(a) Includes swaps and physical and financial contracts.
(b) Unobservable inputs were weighted by the relative fair value of the instrument.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts	**2023**	**2022**	**2023**	**2022**
Net derivative balance at beginning of period	$ (1,279)	$ 4,546	$ (4,888)	$ (2,738)
Total net gains (losses) realized/unrealized:				
Deferred as a regulatory asset or liability	(9,999)	1,179	(67,285)	10,473
Settlements	18,103	4,827	68,681	2,440
Transfers into Level 3 from Level 2	—	(144)	(1,289)	40
Transfers from Level 3 into Level 2	—	—	11,606	193
Net derivative balance at end of period	$ 6,825	$ 10,408	$ 6,825	$ 10,408
Net unrealized gains included in earnings related to instruments still held at end of period	$ —	$ —	$ —	$ —

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 short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 3 for our long-term debt fair values.

12. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in Nuclear Decommissioning Trusts, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments at their fair value on our Condensed Consolidated Balance Sheets. See Note 11 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts — APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. 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. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities.

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Active Union Employee Medical Account — APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2022, APS was reimbursed $15 million for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	September 30, 2023					
	Fair Value					
Investment Type:	**Nuclear Decommissioning Trusts**	**Other Special Use Funds**	**Total**		**Total Unrealized Gains**	**Total Unrealized Losses**
Equity securities	$ 444,063	$ 55,253	$ 499,316		$ 327,887	$ (23)
Available for sale-fixed income securities	693,510	311,624	1,005,134	(a)	623	(74,383)
Other	(17,110)	1,282	(15,828)	(b)	—	—
Total	$ 1,120,463	$ 368,159	$ 1,488,622		$ 328,510	$ (74,406)

(a) As of September 30, 2023, the amortized cost basis of these available-for-sale investments is $1,079 million.
(b) Represents net pending securities sales and purchases.

	December 31, 2022					
	Fair Value					
Investment Type:	**Nuclear Decommissioning Trusts**	**Other Special Use Funds**	**Total**		**Total Unrealized Gains**	**Total Unrealized Losses**
Equity securities	$ 487,240	$ 66,974	$ 554,214		$ 334,817	$ (267)
Available for sale-fixed income securities	582,343	279,294	861,637	(a)	3,177	(68,795)
Other	3,827	963	4,790	(b)	—	(29)
Total	$ 1,073,410	$ 347,231	$ 1,420,641		$ 337,994	$ (69,091)

(a) As of December 31, 2022, the amortized cost basis of these available-for-sale investments is $927 million.
(b) Represents net pending securities sales and purchases.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Three Months Ended September 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2023			
Realized gains	$ 34,897	$ —	$ 34,897
Realized losses	(11,568)	(547)	(12,115)
Proceeds from the sale of securities (a)	487,324	90,816	578,140
2022			
Realized gains	$ 788	$ —	$ 788
Realized losses	(6,908)	—	(6,908)
Proceeds from the sale of securities (a)	153,573	65,244	218,817

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

	Nine Months Ended September 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2023			
Realized gains	$ 71,338	$ —	$ 71,338
Realized losses	(28,454)	(547)	(29,001)
Proceeds from the sale of securities (a)	922,270	223,398	1,145,668
2022			
Realized gains	$ 8,093	$ —	$ 8,093
Realized losses	(26,582)	—	(26,582)
Proceeds from the sale of securities (a)	783,232	127,255	910,487

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at September 30, 2023, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 18,012	$ 59,191	$ 18,891	$ 96,094
1 year – 5 years	194,625	42,158	184,682	421,465
5 years – 10 years	163,662	—	2,788	166,450
Greater than 10 years	317,211	3,914	—	321,125
Total	$ 693,510	$ 105,263	$ 206,361	$ 1,005,134

13. Changes in Accumulated Other Comprehensive Loss

The following tables show the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments	Total
Three Months Ended September 30				
Balance June 30, 2023	$ (32,318)		$ 727	$ (31,591)
OCI before reclassifications	—		659	659
Amounts reclassified from accumulated other comprehensive loss	498	(a)	—	498
Balance September 30, 2023	$ (31,820)		$ 1,386	$ (30,434)
Balance June 30, 2022	$ (55,097)		$ 283	$ (54,814)
OCI before reclassifications	—		513	513
Amounts reclassified from accumulated other comprehensive loss	1,001	(a)	—	1,001
Balance September 30, 2022	$ (54,096)		$ 796	$ (53,300)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 5.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Pension and Other Postretirement Benefits		Derivative Instruments	Total
Nine Months Ended September 30				
Balance December 31, 2022	$ (32,332)		$ 897	$ (31,435)
OCI (loss) before reclassifications	(982)		489	(493)
Amounts reclassified from accumulated other comprehensive loss	1,494	(a)	—	1,494
Balance September 30, 2023	$ (31,820)		$ 1,386	$ (30,434)
Balance December 31, 2021	$ (53,885)		$ (976)	$ (54,861)
OCI (loss) before reclassifications	(3,213)		1,772	(1,441)
Amounts reclassified from accumulated other comprehensive loss	3,002	(a)	—	3,002
Balance September 30, 2022	$ (54,096)		$ 796	$ (53,300)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 5.

The following tables show the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits	
Three Months Ended September 30		
Balance June 30, 2023	$ (15,547)	
OCI before reclassifications	—	
Amounts reclassified from accumulated other comprehensive loss	444	(a)
Balance September 30, 2023	$ (15,103)	
Balance June 30, 2022	$ (36,221)	
OCI before reclassifications	—	
Amounts reclassified from accumulated other comprehensive loss	909	(a)
Balance September 30, 2022	$ (35,312)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 5.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Pension and Other Postretirement Benefits	
Nine Months Ended September 30		
Balance December 31, 2022	$ (15,596)	
OCI (loss) before reclassifications	(839)	
Amounts reclassified from accumulated other comprehensive loss	1,332	(a)
Balance September 30, 2023	$ (15,103)	
Balance December 31, 2021	$ (34,880)	
OCI (loss) before reclassifications	(3,160)	
Amounts reclassified from accumulated other comprehensive loss	2,728	(a)
Balance September 30, 2022	$ (35,312)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 5.

14. Leases

We lease certain land, buildings, vehicles, equipment and other property through operating rental agreements with varying terms, provisions, and expiration dates. APS also has certain purchased power and energy storage agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2023 through 2073. Substantially all of our leasing activities relate to APS.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 6 for a discussion of VIEs.

APS has purchased power lease agreements that allow APS the right to the generation capacity from certain natural-gas fueled generators during certain months of each year throughout the term of the arrangements. As APS only has rights to use the assets during certain periods of each year, the leases have non-consecutive periods of use. APS does not operate or maintain the leased assets. APS controls the dispatch of the leased assets during the months of use and is required to pay a fixed monthly capacity payment during these periods of use. For these types of leased assets, APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. In addition to the fixed monthly capacity payments, APS must also pay variable charges based on the actual production volume of the assets. The variable consideration is not included in the measurement of our lease obligation.

In January 2023, APS modified two existing purchase power operating lease agreements. Among other changes, the modifications extend the expiration dates of these contracts from October 2027 to October 2032 for one of the leases, and from September 2026 to October 2034 for the other lease. These lease agreements previously commenced in 2020 and 2021.

APS has executed various energy storage purchased power lease agreements that allow APS the right to charge and discharge energy storage facilities. The first of these energy storage leases commenced in September 2023, and is classified as an operating lease. This agreement provides APS the use of the energy storage facility through May 2043. APS pays a fixed monthly capacity price for rights to use the leased asset. APS does not operate or maintain the energy storage facility and has no purchase options or residual value guarantees relating to the lease asset. For this class of energy storage lease assets, APS has elected to separate the lease and non-lease components.

The following tables provide information related to our lease costs (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Operating Lease Cost - Purchased Power & Energy Storage Lease Contracts	$ 81,456	$ 68,714	$ 117,111	$ 97,854
Operating Lease Cost - Land, Property, and Other Equipment	4,820	4,456	14,394	13,597
Total Operating Lease Cost	86,276	73,170	131,505	111,451
Variable lease cost (a)	48,572	42,188	113,296	103,493
Short-term lease cost	9,114	5,065	17,918	8,568
Total lease cost	$ 143,962	$ 120,423	$ 262,719	$ 223,512

(a) Primarily relates to purchased power lease contracts.

Lease costs are primarily included as a component of operating expenses on our Condensed Consolidated Statements of Income. Lease costs relating to purchased power and energy storage lease contracts are recorded in fuel and purchased power on the Condensed Consolidated Statements of Income and are subject to recovery under the PSA or RES. See Note 4. The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable purchased power lease contracts. Payments under most renewable purchased power lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the fuel source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements, we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheet.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information related to the maturity of our operating lease liabilities (dollars in thousands):

	September 30, 2023		
Year	**Purchased Power & Energy Storage Lease Contracts**	**Land, Property & Equipment Leases**	**Total**
2023 (remaining three months of 2023)	$ 30,520	$ 4,004	$ 34,524
2024	108,201	13,964	122,165
2025	124,968	11,480	136,448
2026	138,692	9,181	147,873
2027	164,613	7,154	171,767
2028	168,410	4,831	173,241
Thereafter	835,813	63,473	899,286
Total lease commitments	1,571,217	114,087	1,685,304
Less imputed interest	347,899	42,188	390,087
Total lease liabilities	$ 1,223,318	$ 71,899	$ 1,295,217

We recognize lease assets and liabilities upon lease commencement. At September 30, 2023, we have lease arrangements that have been executed, but have not yet commenced. We expect the total fixed consideration paid for these arrangements, which includes both lease and non-lease payments, will approximate $7.1 billion over the terms of the arrangements. These arrangements primarily relate to energy storage assets. The lease commencement dates for these arrangements have experienced delays. APS continues to work with the lessors to determine revised commencement dates. We expect lease commencement dates ranging from November 2023 through June 2025, with lease terms expiring through May 2045. As a result of these delays and other events, APS has received cash proceeds from the lessors prior to lease commencement. Proceeds received from lessors relating to energy storage PPA leases are accounted for as lease incentives on our Condensed Consolidated Balance Sheets, and upon lease commencement are amortized over the associated lease term. For regulatory purposes, the proceeds received by APS relating to these PPA leases are treated as a reduction to fuel and purchased power cost through the PSA in the period proceeds are received. See Note 4.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following tables provide other additional information related to operating lease liabilities (dollars in thousands):

	Nine Months Ended September 30, 2023		Nine Months Ended September 30, 2022
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$ 89,304		$ 86,323
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	599,281	(a)	14,533

	September 30, 2023	December 31, 2022
Weighted average remaining lease term	10 years	7 years
Weighted average discount rate (b)	4.53 %	2.21 %

(a) Primarily relates to the two purchased power operating lease agreements that were modified in January 2023.

(b) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements, we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

15. Asset Retirement Obligations

During the nine months ended September 30, 2023, the Company revised its cost estimates for existing Asset Retirement Obligations ("ARO") for the following:

- Cholla coal-fired power plant related to the closure of ponds and facilities, which resulted in an increase to the ARO of approximately $36 million.
- Four Corners coal-fired power plant, which resulted in a decrease of approximately $7 million.
- Navajo coal-fired power plant, which resulted in an increase of approximately $8 million.
- Palo Verde received a new decommissioning study, which resulted in an increase to the ARO in the amount of $33 million, an increase in the plant in service of $34 million and an increase in the regulatory liability of $1 million.

APS battery energy storage systems may have asset retirement obligations for the removal of the asset. As of September 30, 2023, no asset retirement obligations have been recorded relating to these types of assets. We are evaluating these asset removal obligations, but do not expect the obligations will be significant.

See additional details in Notes 4 and 8.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following schedule shows the change in our asset retirement obligations for the nine months ended September 30, 2023 (dollars in thousands):

	2023
Asset retirement obligations at January 1, 2023	$ 797,762
Changes attributable to:	
Accretion expense	32,763
Settlements	(5,750)
Estimated cash flow revisions	70,405
Asset retirement obligations at September 30, 2023	$ 895,180

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See Note 4 for detail of regulatory liabilities.

16. Sale of Bright Canyon Energy

On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary, BCE, to Ameresco. The transaction is accounted for as the sale of a business and is structured to close in multiple stages that are expected to be completed by the end of 2023, or a later date as permitted by the agreement. Certain investments and assets that BCE held as of September 30, 2023, including the TransCanyon joint venture and holdings in the two Tenaska wind farm investments, were not included in the BCE Sale and were instead transferred to PNW Power, a newly-formed, wholly-owned subsidiary of Pinnacle West. The BCE Sale does not include a $31 million equity bridge loan relating to BCE's Los Alamitos project, which was paid in full by Pinnacle West on August 4, 2023. Other than these retained investments and the debt instrument, all the BCE assets and liabilities are included in the BCE Sale and are expected to transfer to Ameresco as a result of the BCE Sale.

The first stage of the BCE Sale closed on August 4, 2023, with the carrying value of net assets transferred to Ameresco totaling $44 million, which included a $36 million construction term loan. See Note 3. The assets and liabilities transferred in this stage related to the BCE Los Alamitos project and were previously primarily classified as construction work in progress and current maturities of long-term debt, respectively. Our Condensed Consolidated Income Statement for the nine months ended September 30, 2023, includes a pretax gain of $6 million relating to this stage of the BCE Sale reported within other income.

As of September 30, 2023, our Condensed Consolidated Balance Sheets include $32 million of assets classified as held for sale, relating to the remaining assets of BCE that are expected to transfer to Ameresco in the second stage of the sale. These assets held for sale include BCE's investment in the Kūpono Solar project, and other projects in various stages of development. The completion of the second stage of the BCE Sale is subject to various conditions precedent, including third-party consents. Prior to being classified as held for sale, these assets were primarily included in the other assets line item within the investments and other assets section on our Condensed Consolidated Balance Sheets. We measure assets held for sale at the lower of carrying value or fair value less cost to sell. For the nine months ended September 30, 2023, no impairment loss was recognized related to the assets classified as held for sale.

As of September 30, 2023, the Condensed Consolidated Balance Sheets include a $34 million note receivable from Ameresco relating to the initial stage of the BCE Sale, which is due by January 2024. The BCE Sale also provides for Pinnacle West to purchase approximately $28 million of investment tax credits that may be generated by the assets included in the BCE Sale from Ameresco by January 2024.

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 2022 Form 10-K and Part II, Item 1A of this report.

OVERVIEW

Business Overview

Pinnacle West is an investor-owned electric utility holding company based in Phoenix, Arizona with consolidated assets of about $24 billion. For over 130 years, Pinnacle West and our affiliates have provided energy and energy-related products to people and businesses throughout Arizona.

Pinnacle West derives essentially all of our revenues and earnings from our principal subsidiary, APS. APS is Arizona's largest and longest-serving electric company that generates safe, affordable and reliable electricity for approximately 1.4 million retail customers in 11 of Arizona's 15 counties. APS is also the operator and co-owner of Palo Verde — a primary source of electricity for the southwest United States.

Inflation

Overall inflation has grown by 3.7% in Phoenix over the past twelve months to August 2023, matching the national inflation rate. The impacts from inflation have varied across separate categories of APS's spending. Sharp price increases have begun to level off from the heightened market in the fourth quarter 2022; however, APS continued to see increases of up to 15% in the third quarter of 2023. APS has seen inflationary impacts in supply constrained categories related to electrical equipment, such as transformers, wire, and cable impacted by high utility demand outpacing manufacturing capacity. Inflation continues to impact service rates and spend categories through pass-through costs such as supplier's increased material costs, cost of insurance, and wage rates.

Even prior to these increases, APS has focused on its customer affordability initiative, which has enabled APS to mitigate against inflationary pressure. This initiative includes identifying efficiency opportunities through APS's LEAN Sigma approach as well as other corporate decisions. For example, APS maintains its inventory to take advantage of lower pricing, when available, and to minimize supply chain delays that can increase the pricing due to expediting fees. Additionally, APS has proactively entered into long-term contracts to hedge against price volatility, which has allowed it to mitigate against several procurement spend areas such as transformers.

Inflation Reduction Act of 2022

On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 ("IRA"). The IRA significantly expands the availability of tax credits for investments in clean energy generation technologies and energy storage. Key provisions that are relevant to the Company's clean energy commitment include (i) an extension of tax credits for solar and wind generation, including a new option for solar investments to claim a

Production Tax Credit ("PTC") in lieu of the Investment Tax Credit ("ITC") beginning in 2022; (ii) expansion of the ITC to cover stand-alone energy storage technology beginning in 2023; and (iii) introduction of a new PTC for nuclear energy produced by existing nuclear energy plants, available from 2024 through 2032. The Internal Revenue Service and U.S. Treasury continue to issue regulations and other guidance which will provide additional details and clarifications regarding how the Company may be able to claim each of these credits.

In addition, the IRA contains several provisions which could create additional tax liabilities for corporations, including a 15% corporate alternative minimum tax for corporations with net profits in excess of $1 billion and a 1% excise tax on stock buybacks. We currently do not believe the Company will be subject to any material tax liabilities as a result of these legislative provisions.

COVID-19

During the COVID-19 pandemic, APS experienced some delays in finished materials and a tight labor market. APS has measures in place to continually monitor and evaluate resource and labor needs and supply chain adequacy but cannot predict whether there will be material supply chain or labor shortages in the future as a result of COVID-19, another pandemic, or otherwise. APS also experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales from commercial and industrial customers increased to levels in line with pre-COVID-19 sales but residential sales continued to be higher than pre-COVID-19 sales.

Due to COVID-19, APS voluntarily suspended disconnections of customers for nonpayment beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS voluntarily began waiving late payment fees of its customers on March 13, 2020. Effective February 1, 2023, late payment fees for residential customers were reinstated, and late payment fees for commercial and industrial customers were reinstated effective May 1, 2022. See Note 4 for additional information regarding the Summer Disconnection Moratorium.

The Coronavirus Aid, Relief, and Economic Security ("CARES") Act allowed employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020, which was approximately $18 million. As of December 31, 2022, we have paid this cash deferral in full.

Strategic Overview

Our strategy is to deliver shareholder value by creating a sustainable energy future for Arizona by serving our customers with clean, reliable, and affordable energy.

Clean Energy Commitment

We are committed to doing our part to make the future clean and carbon-free. As Arizona stewards, we do what is right for the people and prosperity of Arizona. Our vision is to create a sustainable energy future for Arizona through providing clean, affordable, and reliable energy. We can accomplish our visions through collaboration with customers, communities, employees, policymakers, shareholders, and other stakeholders. Our clean energy goal is based on sound science and supports continued growth and economic development while maintaining reliability and affordable prices for APS's customers.

APS's clean energy goals consist of three parts:

- A 2050 goal to provide 100% clean, carbon-free electricity;
- A 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and
- A commitment to exit from coal-fired generation by 2031.

APS's ability to successfully execute its clean energy commitment is dependent upon a number of important external factors, some of which include a supportive regulatory environment, sales and customer growth, development of clean energy technologies, and continued access to capital markets.

2050 Goal: 100% Clean, Carbon-Free Electricity. Achieving a fully clean, carbon-free energy mix by 2050 is our aspiration. The 2050 goal will involve new thinking and depends on improved and new technologies.

2030 Goal: 65% Clean Energy. APS has an energy mix that is already 50% clean with existing plans to add more renewables and energy storage before 2025. By building on those plans, APS intends to attain an energy mix that is 65% clean by 2030, with 45% of APS's generation portfolio coming from renewable energy. "Clean" is measured as percent of energy mix, which includes all carbon-free resources like nuclear, renewables, and demand-side management. "Renewable" energy includes generation sources such as solar, wind, and biomass, and is measured in accordance with the ACC's Renewable Energy Standard as a percentage of retail sales. This target will serve as a checkpoint for our resource planning, investment strategy, and customer affordability efforts as APS moves toward a 100% clean, carbon-free energy mix by 2050.

2031 Goal: Exit Coal-Fired Generation. The plan to exit coal-fired generation by 2031 will require APS to stop relying on coal-generation at Four Corners. APS has permanently retired more than 1,000 MW of coal-fired electric generating capacity. These closures and other measures taken by APS have resulted in lower annual carbon emissions, which were 24% lower in 2022 compared to 2005. In addition, APS has committed to end the use of coal at its remaining Cholla units during 2025.

APS understands that the transition away from coal-fired power plants toward a clean energy future will pose unique economic challenges for the communities around these plants. We worked collaboratively with stakeholders and leaders of the Navajo Nation to consider the impacts of ceasing operation of APS coal-fired power plants on the communities surrounding those facilities to propose a comprehensive Coal Community Transition ("CCT") plan. The proposed framework provided substantial financial and economic development support to build new economic opportunities and addresses a transition strategy for plant employees. We are committed to continuing our long-running partnership with the Navajo Nation in other areas as well, including expanding electrification and developing tribal renewable energy projects. Our proposed CCT plan supported the Navajo Nation, where Four Corners is located, the communities surrounding the Cholla Power Plant, and the Hopi Tribe, which was impacted by closure of the Navajo Plant. On November 2, 2021, the ACC approved an amended 2019 Rate Case ROO that will require (i) equal payments over a three-year period that total $10 million to the Navajo Nation, (ii) a $1 million one-time payment to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (iii) a $500,000 one-time payment to the Navajo County communities within 60 days of the 2019 Rate Case decision, (iv) up to $1.25 million for electrification of homes and businesses on the Hopi reservation, and (v) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. The payments and expenditures are attributable to the planned exits from Four Corners and Cholla, along with the prior closure of the Navajo Plant. All ordered payments and expenditures would be recoverable through rates. See Note 4 for a discussion of the CCT plan.

Consistent with the 2019 Rate Case decision, as of September 2023, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) $6.66 million to the Navajo Nation; (ii) $0.5 million to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) $1 million to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County communities for CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The ACC has authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservations. To support the expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations, a census was conducted of the unelectrified homes and businesses in each that are also within APS service territory. The census work was fully completed in November 2022, and discussions regarding the use of the $1.25 million for electrification of homes and businesses on both the Navajo Nation and Hopi reservations are ongoing.

On September 28, 2022, ACC Staff filed their staff report in the Matter of Impact of the Closures of Fossil-Based Generation Plan on Impacted Communities. APS and other interested parties filed comments on the report. On October 21, 2022, ACC Staff filed a revised report and proposed order. The revised report and proposed order recommended that funds for CCT shall not be collected from rate payers. On December 8, 2022, the ACC voted against ACC Staff's proposed order, and on April 17, 2023, the ACC closed the docket. Any further action on CCT issues will take place in utility rate cases, including the currently pending 2022 Rate Case. APS cannot predict the outcome of this matter.

In June 2021, APS and the owners of Four Corners entered into an agreement that would allow Four Corners to operate seasonally at the election of the owners as early as fall 2023, subject to the necessary governmental approvals and conditions associated with changes in plant ownership. Under seasonal operation, one generating unit would be shut down during seasons where electricity demand is reduced, such as the winter and spring. The other unit would remain online year-round, subject to market conditions as well as planned maintenance outages and unplanned outages. APS has elected not to begin seasonal operation in November 2023, due to market conditions.

Renewables. APS's IRP (see Note 4 for additional information) establishes the path to meeting our clean energy commitment and maintaining reliable electric service for our customers. APS intends to strengthen its already diverse energy mix by increasing its investments in carbon-free resources. Our IRP rapidly adds clean energy and storage resources while maintaining reliable and affordable service. Its near-term actions are focused on clean, reliable energy and positive customer outcomes and include: (a) competitive all source requests for proposal ("RFPs") that provide an on-ramp to procure additional clean energy resources such as solar, wind, energy storage, and DSM resources, all of which lead to a cleaner grid and (b) strategic, short-term wholesale market purchases from a combination of existing merchant natural gas units, neighboring utility systems and wholesale market participants that ensure operational reliability.

APS has a diverse portfolio of existing and planned renewable resources, including solar, wind, geothermal, biomass and biogas, that supports our commitment to clean energy. This commitment is already strengthened by Palo Verde, the nation's largest carbon-free, clean energy resource, which provides the foundation for reliable and affordable service for APS customers. APS's longer-term clean energy strategy includes pursuing the right mix of purchased power contracts for new facilities, procurement of new facilities to be owned by APS, and the ongoing development of distributed energy resources. This balance will ensure an appropriately diverse portfolio designed to achieve the same operational reliability and customer affordability as APS's near-term strategies. In addition, APS is actively seeking to include future facility purchase options in its PPAs that will enable investments with greater financial flexibility.

APS uses competitive "all source" RFPs to pursue market resources that meet its system needs and offer the best value for customers. APS selects projects based on cost, ability to meet system requirements and commercial viability, taking into consideration timing and likelihood of successful contracting and development. Under current market conditions, APS must aggressively contract for resources that can withstand supply chain and other geopolitical pressures. Available projects are guided by IRP timelines and quantities and APS maintains a flexible approach that allows it to optimize system reliability and customer affordability through the RFP process. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

In December 2020, APS issued two RFPs: (i) a battery storage RFP for projects to be located at two AZ Sun sites, and (ii) an all-source RFP that solicited resources to meet our clean energy needs and capacity to maintain system reliability, and was later amended to include a request for 150 MW of solar resources to be developed on APS property and owned by APS (collectively, the "December 2020 RFPs"). As a result of the December 2020 RFPs, APS executed two solar plus storage PPAs totaling 275 combined MW, a PPA for a 238 MW wind resource, and two energy storage PPAs for a combined 300 MW; extended an existing natural gas tolling agreement; and also executed an engineering, procurement, and construction contract in November 2021 for a 150 MW solar resource to be owned by APS and which entered into service in 2023.

In May 2022, APS issued an all-source RFP to address resource needs for 2025 and beyond ("2022 RFP"). The 2022 RFP solicited competitive proposals for approximately 1,000 MW to 1,500 MW of resources, including up to 600 MW to 800 MW of renewable resources to meet the needs of 2025 and 2026 while considering resources that can be online as late as 2027. The 2022 RFP stopped accepting bids on July 15, 2022, and APS sent notifications to shortlisted bidders on September 23, 2022. As a result of the 2022 RFP, and as of September 30, 2023, APS has signed five solar plus energy storage PPAs totaling 1,046 MW of solar resources, paired with approximately 1,087 MW of energy storage resources, another 630 MW of stand-alone energy storage, and a PPA for 216 MW of wind resources. One of the solar plus energy storage PPAs replaced two PPAs with qualifying facilities under the Public Utility Regulatory Policies Act of 1978, which were terminated due to project delays as discussed in Note 4. In addition to the renewable resources described above, the 2022 RFP also resulted in the extension of tolls at two merchant gas facilities.

On June 30, 2023, APS issued an all-source RFP (the "2023 RFP") seeking approximately 1,000 MW of reliable capacity, including at least 700 MW of renewable resources with a focus on in-service dates between 2026 and 2028. Bids from the 2023 RFP were received on September 6, 2023, and APS plans to execute agreements starting in late 2023 through 2024.

The following table summarizes the resources in APS's renewable energy portfolio that are in operation or under development as of September 30, 2023. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting, and interconnection of the projects to the electric grid.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)	
Total APS Owned: Solar	415	—	
Purchased Power Agreements Renewables:			
Solar	370	1,261	
Wind	637	216	
Geothermal	10	—	
Biomass	14	—	
Biogas	3	—	
Total Purchased Power Agreements	1,034	1,477	
Total Distributed Energy: Solar (a)	1,572	90	(b)
Total Renewable Portfolio	3,021	1,567	

(a) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in Direct Current and is converted to Alternating Current for reporting purposes.
(b) Applications received by APS that are not yet installed and online.

Energy Storage. APS deploys a number of advanced technologies on its system, including energy storage. Energy storage provides capacity, improves power quality, can be utilized for system regulation and, in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage also aids in integrating renewable generation by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale energy storage projects to meet customer reliability requirements, increase renewable utilization, and to further our understanding of how storage works with other advanced technologies and the grid.

In 2018, APS issued an RFP for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APS's AZ Sun sites. This contract completes the addition of storage on current APS-owned utility-scale solar facilities. These battery storage facilities have entered into service.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the Power Supply Adjustment ("PSA"). APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in late 2023 and 2024.

As a result of the December 2020 RFPs, APS executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW, and (b) two PPAs for solar plus energy storage resources totaling 275 MW. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021 and on April 13, 2022 for the remaining project. APS since terminated one energy storage PPA totaling 200 MW due to project delays. Service under a PPA for a solar plus energy storage resource of 60 MW began in 2023 and service for the remaining agreements is expected to begin in 2024.

As a result of the 2022 RFP, APS has executed five 20-year PPAs for solar plus storage resources totaling 1,046 MW of solar resources paired with approximately 1,087 MW of energy storage resources, and another four 20-year PPAs for stand-alone energy storage resources totaling 630 MW. The PPAs are subject to ACC approval to enable cost recovery through the PSA. All of these agreements have received approval to be recovered through the PSA. Service under these agreements is expected to begin in 2024 and 2025.

APS currently plans to install more than 2,400 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of resources solicited through current and future RFPs.

The following table summarizes the resources in APS's energy storage portfolio that are in operation or under development as of September 30, 2023. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)		Net Capacity Planned / Under Development (MW)	
APS Owned: Energy Storage	141	(a)	60	(b)
Purchase Power Agreements - Energy Storage	60		2,182	
Customer-Sited Energy Storage	28		19	
Total Energy Storage Portfolio	**229**		**2,261**	

(a) Includes 0.3 MW of APS-owned customer-sited batteries.
(b) Includes 60 MW of capacity that was mechanically completed in June 2023 but has not yet entered commercial operation as of September 30, 2023.

Palo Verde. Palo Verde, one of the nation's largest carbon-free, clean energy resources, will continue to be a foundational part of APS's resource portfolio. Palo Verde is not just the cornerstone of our current clean energy mix; it also is a significant provider of clean energy to the southwest United States. The plant is a critical asset to the Southwest, generating more than 32 million MWh annually – enough power for roughly 3.4 million households, or approximately 8.5 million people. Its continued operation is important to a carbon-free and clean energy future for Arizona and the region, as a reliable, continuous, affordable resource and as a large contributor to the local economy.

Affordable

Building upon existing cost management efforts, APS launched a customer affordability initiative in 2019. The initiative was implemented company-wide to thoughtfully and deliberately assess our business processes and organizational approaches to completing high-value work and achieving internal efficiencies. APS continues to drive this initiative by identifying opportunities to streamline its business processes to assist in mitigating cost increases, increasing employee retention, and improving customer satisfaction.

Participation in the Energy Imbalance Market ("EIM") continues to be a tool for creating savings for APS's customers from the real-time, voluntary market. APS continues to expect that its participation in EIM will lower its fuel and purchased-power costs, improve situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources. APS continues to evaluate opportunities that benefit our customers and is exploring opportunities to move to a day-ahead market with the expectation of reliably achieving incrementally greater cost savings and using the region's increasing renewable resources more efficiently. As part of that effort, APS is exploring several options. APS is in discussions with the current EIM operator, the CAISO, the Western Resource Adequacy Program, the Western Markets Exploratory Group, and the Southwest Power Pool. Each of these explorations also involve other entities and are being undertaken to evaluate the feasibility and cost/benefit of creating a voluntary day-ahead market.

Reliable

While our energy mix evolves, the obligation to deliver reliable service to our customers remains. APS is managing through significant growth in the Phoenix metropolitan area while experiencing supply chain issues similar to other industries.

Planned investments will support operating and maintaining the grid, updating technology, accommodating customer growth, and enabling more renewable energy resources. Our advanced distribution management system allows operators to locate outages, control line devices remotely and helps them coordinate more closely with field crews to safely maintain an increasingly dynamic grid. The system will also integrate a new meter data management system that will increase grid visibility and give customers access to more of their energy usage data.

Wildfire safety remains a critical focus for APS and other utilities. We have increased investment in fire mitigation efforts to clear defensible space around our infrastructure, continue ongoing system upgrades, build partnerships with government entities and first responders and educate customers and communities. These programs contribute to customer reliability, responsible forest management and safe communities. With recent wildfire events in Hawaii and across North America, we have been and will continue to devote substantial efforts to analyzing and developing enhancements to our systems and processes to mitigate fire risk within our service territory and communities, including by hardening our infrastructure, deploying new technologies where appropriate, increasing our awareness, implementing operational changes, and enhancing our wildfire response capabilities. We also continue to evaluate policy and regulatory options as well as insurance programs to mitigate the impact of wildfire events.

The new units at our modernized Ocotillo Power Plant provide cleaner-running and more efficient units. They support reliability by responding quickly to the variability of solar generation and delivering energy in the late afternoon and early evening when solar production declines as the sun sets and customer demand peaks. APS continues to evaluate options to meet growing energy demand and ensure grid reliability, including through upgrades to and/or modernization of additional existing gas facilities.

In October of 2021, APS announced plans to evaluate regional market solutions as part of the informal Western Markets Exploratory Group ("WMEG"). As part of WMEG, APS is exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations. WMEG hopes to identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers. APS is unable to predict the outcome of these discussions.

APS's key elements to delivering reliable power include resource planning, sufficient reserve margins, customer partnerships to manage peak demand, fire mitigation, and operational preparedness. Seasonal readiness procedures at APS also include inspections to ensure good material conditions and critical control system surveys. APS also plans for the unexpected by conducting emergency operations drills and coordinating on fire and emergency management with federal, state, and local agencies.

Customer-Focused

Recognizing that creating customer value is inextricably linked to increasing shareholder value, APS's focus remains on its customers and the communities it serves. Accordingly, it is APS's goal to achieve an industry-leading, best-in-class customer experience, while demonstrating compassion and advocacy for its customers. This multi-year objective includes incrementally improving APS's J.D. Power ("JDP") overall customer satisfaction ratings to achieve first quartile ranking in its peer set comprised of large investor-owned utilities. APS has made noteworthy progress on that front.

As previously disclosed, APS's JDP Residential rankings for overall customer satisfaction improved in each of 2020, 2021 and 2022, and APS ended 2022 as one of the most improved utilities in the nation for both residential and business customer satisfaction. Residential customer satisfaction finished 2022 ranked in the second quartile among large investor-owned utilities, and business customer satisfaction ranked in the first quartile of utilities nationally.

Developing Clean Energy Technologies

Electric Vehicles

APS is making electric vehicle charging more accessible for its customers and helping Arizona businesses, schools and governments electrify their fleets. In 2021, APS continued its expansion of its Take Charge AZ Pilot Program. As of September 30, 2023, APS had installed 734 Level 2 ("L2") charging ports at customer locations, with more stations expected to be added through 2023. The program provides charging equipment, installation, and maintenance to business customers, government agencies, non-profits, and multifamily housing communities. In addition to the L2 charging stations, APS has deployed DC fast charging ("DCFC") stations that are owned and operated by APS at five locations in Arizona. The charging stations, which are open for public use, are located in Show Low, Sedona, Prescott, Globe, and Payson, Arizona. Each location features at least two 350 kilowatt DCFC ports. Charging at these stations will be accessible through the Electrify America charging network. APS has a goal to reach 450,000 light-duty electric vehicles in its service territory by 2030.

Additionally, as part of APS's DSM Plan, APS has launched an Electric Vehicle Charging Demand Management Pilot Program to proactively address the growing electric demand from electric vehicle charging as electric vehicles become more widely adopted. This program includes the APS SmartCharge data gathering program, a $250 residential electric vehicle smart charger rebate for qualifying electric vehicle chargers, Fleet Advisory Services, and a $100 rebate to home builders for new homes to be built EV ready with 240V charging station garage outlets. APS filed its 2023 DSM Plan on November 30, 2022, which proposes two new programs, an expanded residential EV Managed Charging Program and a Commercial Make-Ready Program. The Commercial Make-Ready Program is intended to help reduce some of the high upfront cost for our customers installing DCFC stations and enables APS to deploy effective load management strategies at these commercial sites. The ACC has yet to decide on the 2023 DSM Plan.

The ACC ordered certain public service corporations, including APS, to develop a long-term, comprehensive statewide transportation electrification plan ("TE Plan") for Arizona. The statewide TE Plan is intended to provide a roadmap for transportation electrification in Arizona, focused on realizing the associated air quality and economic development benefits for all residents in the state along with understanding the impact of electric vehicle charging on the grid. APS actively participated in the development of that plan, which was approved by the ACC in December 2021. In the decision, the ACC also ordered APS and another large Arizona electric public service corporation to each develop and submit for ACC approval their own TE Plans and corresponding budget for 2023. Accordingly, APS met its compliance obligation and filed both a

2023 TE Plan on June 1, 2022 and a supplemental TE Plan on November 30, 2022. The ACC has yet to decide on the 2023 TE Plan. APS filed its required annual TE progress reports on March 15 and its 2023 Mid-Year progress report on September 15, 2023. In accordance with an extension granted by the ACC, APS intends to file a 2024 TE Plan by November 30, 2023.

Hydrogen Production

The Southwest Clean Hydrogen Innovation Network ("SHINe") regional hub was formed due to the Infrastructure Investment and Jobs Act ("IIJA"), also known as the Bipartisan Infrastructure Bill, which was signed into law on November 15, 2021. Among other things, the IIJA included money for regional clean hydrogen hubs, and on February 15, 2022, the Department of Energy ("DOE") announced a request for information to collect feedback from stakeholders to inform the implementation and design of the regional hubs.

On May 12, 2022, Arizona's three public universities, along with four Arizona energy providers, including APS, announced the formation of a new, interdisciplinary coalition, called the Arizona Center for a Carbon Neutral Economy ("AzCaNE"), with the goal of attaining a carbon neutral economy in Arizona. AzCaNE's first action was to pursue the creation of an Arizona-led approach to securing regional clean hydrogen hub funding. Leading professionals from the seven founding participants, along with representatives of Arizona, the Navajo Nation and companies working to develop a hydrogen ecosystem within Arizona, make up the Governance Committee for AzCaNE's current efforts.

On September 22, 2022, the DOE opened applications for the up to $7 billion program to create six to ten regional clean hydrogen hubs across the country. Concept papers for each regional hub were due by November 7, 2022, and AzCaNE submitted a concept paper for the SHINe regional hub, which also includes projects in Nevada. On December 27, 2022, the SHINe regional hub was one of thirty-three regional hubs encouraged to submit a full application by the DOE. SHINe's full application was submitted to the DOE on April 7, 2023. On October 13, 2023, the DOE announced the seven regional hubs to be included in the program and SHINe was not chosen. APS is currently maintaining a participatory role in AzCaNE, but APS's role, if any, in the SHINe regional hub's future endeavors, if any, has yet to be determined.

Carbon Capture

Carbon Capture Utilization and Storage ("CCUS") technologies can isolate CO_2 and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. CCUS technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could offer the potential to keep in operation existing generators that otherwise would need to be retired. APS will continue to monitor this emerging technology, particularly in regard to EPA's proposed GHG rule. On May 24, 2023, the EPA proposed regulations for GHG emissions that would, among other things, require CCUS technologies for certain classifications of coal-, oil-, and natural gas-fired electricity generating units. See Note 8 for more information. APS cannot predict the outcome of this proposed rule.

Environmental, Social, and Governance ("ESG") Practices

Pinnacle West has been integrating ESG practices into its core work for almost 30 years. As a business strategy, we seek solutions that provide "shared value," meaning solutions that address societal and environmental challenges in a way that also delivers business value. Our commitment extends beyond implementing sustainability practices; we are dedicated to working with our stakeholders to identify and address the sustainability issues that we are uniquely positioned to impact through our business. In 2020, in support of our clean energy commitment and the growing focus on sustainability within our organization, we increased our efforts by dedicating a new Sustainability Department at Pinnacle West to integrating ESG best practices into the everyday work of the Company.

The Sustainability Department engaged the Electric Power Research Institute ("EPRI") and leveraged input from employees, large customers, limited-income advocates, economic development groups, environmental non-governmental organizations, leading sustainability academics and other stakeholders to identify and assess the sustainability issues that matter most. In total, 23 Priority Sustainability Issues ("PSIs") were identified and prioritized. The most critical category, Integral Shared Value, includes four issues deemed most important and most able to be impacted by our actions: clean energy, customer experience, energy access and reliability and safety and health. These Integral PSIs provide the foundation for informing our strategic direction, creating a framework for incorporating best practices and driving enterprise-wide alignment and accountability. The Company also focused on utility benchmarking best practices within these four Integral Shared Value PSIs. We are utilizing the benchmarking information to inform decisions about opportunities for improvement in our ESG performance.

The Company established a Social Issues Committee Framework to focus on strengthening our governance and consideration of social issues that arise. The purpose of the framework is to provide a process for considering emergent social issues, and for determining whether or how best to engage. The committee's responsibility is to determine, using a set of principles grounded in the APS Promise and the PSIs, whether engagement on specific emergent social issues is appropriate and, if so, how best to engage.

The Company also finalized an ESG Strategic Framework to guide our work. The framework is based upon three foundational pillars: ESG Policy Advocacy (we advocate for policy that supports our clean energy goals); Driving Performance (improving our ESG performance in the most important areas, including our PSIs); and effectively communicating and amplifying our ESG story to our various stakeholders, including investors, customers, employees and beyond. The ESG Strategic Framework has guided our ESG activities, allowing the Sustainability Department to prioritize projects and collaborate with our teams in the Company. The Company also developed an ESG Narrative, aligned to the APS Promise, to guide the Company's communications strategy internally and externally to customers to effectively share APS's sustainability story.

Regulatory Overview

2022 Retail Rate Case

APS filed an application with the ACC on October 28, 2022 (the "2022 Rate Case") seeking an increase in annual retail base rates on the date rates become effective ("Day 1") of a net $460 million. This Day 1 net impact represents a total base revenue deficiency of $772 million offset by proposed adjustor transfers of cost recovery to annual retail rates and adjustor mechanism modifications. The average annual customer bill impact of APS's request on Day 1 is an increase of 13.6%.

The principal provisions of APS's application are:

- a test year comprised of twelve months ended June 30, 2022, adjusted as described below;
- an original cost rate base of $10.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	48.07 %	3.85 %
Common stock equity	51.93 %	10.25 %
Weighted-average cost of capital		7.17 %

- 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 rate of $0.038321 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs;
- modification of its adjustment mechanisms including:
  - eliminate the Environmental Improvement Surcharge ("EIS") and collect costs through base rates,
  - eliminate the Lost Fixed Cost Recovery ("LFCR") mechanism and collect costs through base rates and the Demand Side Management Adjustment Charge ("DSMAC"),
  - maintain as inactive the Tax Expense Adjustor Mechanism ("TEAM"),
  - maintain the Transmission Cost Adjustment ("TCA") mechanism,
  - modify the performance incentive in the DSMAC, and
  - modify the Renewable Energy Adjustment Charge ("REAC") to include recovery of capital carrying costs of APS owned renewable and storage resources;
- changes to its limited-income program, including a second tier to provide an additional discount for customers with greater need; and
- twelve months of post-test year plant to reflect used and useful projects that will be placed into service prior to July 1, 2023.

On June 5, 2023 and June 15, 2023, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommends among other things, (i) a $251 million revenue increase or, as an alternative, a $312 million revenue increase, (ii) a 9.6% return on equity, (iii) a 0.0% fair value increment or, as an alternative, a 0.75% fair value increment, and (iv) a continuation of a 12-month post-test year plant. RUCO recommends, among other things, (i) an $84.9 million revenue increase, (ii) an 8.2% return on equity or, as an alternative, an 8.7% return on equity if the ACC imputes a hypothetical capital structure with a 46% equity layer, (iii) a fair value increment of 0.0%, and (iv) a reduction of post-test year plant to six months.

On July 12, 2023, APS filed rebuttal testimony addressing the ACC Staff and intervenors' direct testimonies. The principal provisions of APS's rebuttal testimony are:

- reducing the revenue requirement increase to $383.1 million;
- maintaining a return on equity request of 10.25%;
- reducing the increment of fair value rate base return to 0.5% from 1.0%;
- maintaining a post-test year plant request of 12 months, plus the Four Corners Effluent Limitation Guidelines ("ELG") project;
- withdrawing the Payment Fee Removal Proposal (net reduction) which was originally requested in APS's initial application;
- maintaining the LFCR mechanism and DSMAC as separate adjustors;
- increasing the PSA annual rate change limit from $0.004/kWh to $0.006/kWh;
- proposing a new System Reliability Benefit ("SRB") recovery mechanism;
- maintaining the REAC in its current state;
- maintaining adjustor base transfers and elimination of EIS; and
- maintaining the request to recover CCT funding.

On July 26, 2023, the ACC Staff, RUCO and other intervenors filed their surrebuttal testimony with the ACC. The ACC Staff adjusted their initial recommendations to, among other things, (i) a $281.9 million revenue increase, (ii) a 9.68% return on equity, (iii) a 0.5% fair value increment, (iv) a continuation of a 12-month post-test year plant that includes the Four Corners ELG project, and (v) support of an increase to the annual PSA increase limit to $0.006/kWh. RUCO maintained their direct position and also recommended further review of the PSA in a second phase of the 2022 Rate Case.

On August 4, 2023, APS filed rejoinder testimony addressing the ACC Staff and intervenors' surrebuttal testimonies. APS's rejoinder testimony included final post-Test Year Plant values, reducing the revenue requirement increase to $377.7 million from $383.1 million. All other major provisions from APS's rebuttal testimony were maintained in its rejoinder testimony.

APS requested that the increase become effective December 1, 2023. However, based on the current status of the proceeding, the rate effective date is currently anticipated to be in early 2024. The hearing for this rate case concluded in early October 2023. APS cannot predict the outcome of its request.

2019 Retail Rate Case

On October 31, 2019, APS filed an application with the ACC (the "2019 Rate Case") seeking an increase in annual retail base rates. On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. See Note 4 for information regarding the 2019 Rate Case ROO.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, which includes a 20-basis point penalty, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant, and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. In addition, the ACC ordered extensive compliance and reporting obligations. APS completed the implementation of the new on-peak hours for residential customers before the September 1, 2022 deadline.

Additionally, consistent with the 2019 Rate Case decision, as of September 2023, APS completed the following payments that will be recoverable through rates related to the CCT: (i) $6.66 million to the Navajo Nation; (ii) $0.5 million to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) $1 million to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County Communities for CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The

ACC has also authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. Expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations is contingent upon completion of a census of the unelectrified homes and businesses in each that are also within APS service territory. The census work was completed in November 2022 and disbursement of the $1.25 million for electrification of homes and businesses is planned to be finalized after discussions with the Navajo Nation and the Hopi Tribe are completed.

On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215.5 million of Four Corners Power Plant ("Four Corners") selective catalytic reduction ("SCR") project investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20-basis-point penalty reduction to the return on equity, among other things. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The Arizona Court of Appeals heard oral arguments on November 30, 2022. On March 6, 2023, the Court issued its opinion in this matter, affirming in part and reversing in part the ACC's decision in the 2019 Rate Case. The Court vacated the 20-basis-point penalty included in the ACC's allowed return on equity, as the Court determined the use of customer service metrics to justify the reduction exceeded the ACC's ratemaking authority. Additionally, the Court vacated the disallowance of $215.5 million of APS's Four Corners SCR investment. The Court remanded the issue to the ACC for further proceedings. The ACC requested an extension of the 30-day deadline to appeal the matter to the Arizona Supreme Court, and the Arizona Supreme Court granted the extension of the deadline to May 8, 2023. The ACC filed an appeal on May 8, 2023, and on May 15, 2023, requested a suspension of the case to allow for settlement discussions between the parties, which was approved by the Court.

On June 14, 2023, APS and the ACC Legal Division filed a joint resolution with the ACC to allow recovery of the $215.5 million in costs related to the installation of the Four Corners SCR, a reversal of the 20-basis point reduction to APS's return on equity from 8.9% to 8.7% as a result of the 2019 Rate Case Decision, and recovery of $59.6 million in revenue lost by APS between December of 2021 and June 20, 2023. The joint resolution provides for a new Court Resolution Surcharge ("CRS") mechanism, which is designed to recover the $59.6 million in revenue lost by APS between December 2021 and June 20, 2023, and the prospective recovery of ongoing costs related to the SCR investments and expense and the allowable return on equity difference in current base rates. On June 21, 2023, the ACC approved the joint resolution and proposals therein for recovery through the CRS mechanism, which became effective on July 1, 2023. The current CRS will be recalculated at the end of the 2022 Rate Case to remove the effects of the prospective recovery related to the allowable return on equity difference. The portion of the CRS representing the recovery of the $59.6 million of lost revenue between December of 2021 and June 20, 2023, $6.4 million of which has been collected as of September 30, 2023, will cease upon full collection of the lost revenue. Finally, recovery of ongoing costs related to the SCR investments will continue until the Company's next rate case in which they can be incorporated therein. On July 18, 2023, the Sierra Club filed an application for rehearing of the Commission's decision. The ACC did not act upon the application within the 20 days, and it was therefore denied by operation of law. Subsequently, the Sierra Club did not file a notice of appeal to the Arizona Court of Appeals, and the time for an appeal has expired.

See Note 4 for information regarding additional regulatory matters.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. The Arizona Court of Appeals heard oral arguments on November 30, 2022. On March 6, 2023, the Court of Appeals issued its opinion in the matter, vacating the ACC's disallowance of the SCR investment and remanding the matter back to the ACC for further review in accordance with ACC rule and the order of the Court of Appeals. On June 21, 2023, the ACC approved a joint settlement filed by APS and the ACC's Legal Division that resolved all issues relating to the 2019 Rate Case decision, including recovery of the cost of the Four Corners SCRs. See above for further discussion on the 2019 Rate Case decision. See Note 4 for additional information regarding the Four Corners SCR cost recovery.

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's strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Company's core expertise in the electric energy industry. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement with Ameresco, Inc. ("Ameresco"), pursuant to which we agreed to sell all of our equity interest in BCE to Ameresco (the "BCE Sale"). The BCE Sale is structured to close in multiple stages that are targeted to be complete by the end of 2023, or a later date as permitted by the agreement. The BCE Sale will result in Ameresco being the sole shareholder of BCE. Certain investment assets previously held by BCE have been reorganized such that they are no longer held by BCE, rather they are held under a new Pinnacle West subsidiary, Pinnacle West Power, LLC ("PNW Power"); this includes the TransCanyon joint venture and BCE's indirect interests in two wind farms developed by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC. See Note 1 and Note 16.

In 2014, BCE formed 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 electric transmission opportunities within the 11 U.S. states that comprise the Western Interconnection, 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. See discussion above regarding the reorganization of these assets into a new subsidiary held by Pinnacle West, PNW Power.

On December 20, 2019, BCE acquired minority ownership positions in two wind farms under development by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek and the 250 MW Nobles 2 wind farms. Clear Creek achieved commercial operation in May 2020 however, BCE determined in the fourth quarter of 2022 that its equity method investments was fully impaired. See Note 8 for a discussion of the Clear Creek wind farm impairment. Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. BCE indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2. See discussion above regarding the reorganization of these assets into a new subsidiary held by Pinnacle West, PNW Power.

BCE started construction on a microgrid facility in Los Alamitos, California ("Los Alamitos") featuring 31 MW of solar, 20 MWh of battery storage, and 3 MW of backup generators. See Note 3 regarding a credit agreement entered into by BCE to finance capital expenditures and related costs for this microgrid project. The BCE holding company owning the Los Alamitos project was transferred and sold to Ameresco on August 4, 2023. See Note 16 for more information.

BCE and Ameresco, Inc. jointly own a special purpose entity that is sponsoring the Kūpono Solar project. This project is a 42 MW solar and battery storage facility in Oʻahu, Hawaii that will supply clean renewable energy and capacity under a 20-year power purchase agreement with Hawaiian Electric Company, Inc. The Kūpono Solar project is expected to be completed in 2024. On April 18, 2023, the Kūpono Solar special purpose entity, entered into a $140 million non-recourse construction financing agreement. The construction financing will convert into a sale leaseback agreement upon commercial operation of the project. As of September 30, 2023, the construction financing agreement required $40 million of sponsor equity, which has been funded by the project's equity participants and which is subject to adjustment under the construction financing agreement. In connection with the financing, Pinnacle West has issued performance guarantees relating to the project. Pinnacle West's investment in the Kūpono Solar project is targeted to transfer to Ameresco in connection with the BCE Sale by the end of 2023, or a later date as permitted by the purchase and sale agreement. See Note 16 for more information.

El Dorado. El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. In particular, El Dorado committed to a $25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of September 30, 2023, El Dorado has contributed approximately $16.9 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a $25 million investment in AZ-VC (formerly the invisionAZ Fund), which is a fund focused on analyzing, investing, managing and otherwise dealing with investments in privately held early stage and emerging growth technology companies and businesses primarily based in the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona. As of September 30, 2023, El Dorado has contributed approximately $6.4 million to AZ-VC. The remainder of the investment will be contributed by El Dorado as investments are selected by AZ-VC.

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 2020 through 2022, retail electric revenues comprised approximately 92% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand, and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 2.0% for the ninth-month period ended September 30, 2023, compared with the prior-year period. For the three years through 2022, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2023 and the average annual growth to be in the range of 1.5% to 2.5% through 2025 based on anticipated steady population growth in Arizona during that period.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 1.0% for the ninth-month period ended September 30, 2023, compared with the prior-year period. While steady customer growth was somewhat offset by weaker usage among residential customers, energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were continued strong sales to commercial and industrial customers and the ramp-up of new data center customers.

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, slower ramp-up of and/or fewer data centers and large manufacturing facilities, slower than expected commercial and industrial expansions, impacts of energy efficiency programs, and growth in DG, and responses to retail price changes. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $5 million.

For the three years through 2022, annual retail electricity sales growth averaged 2.5%, adjusted to exclude the effects of weather variations. Due to the expected growth of several large data centers and new large manufacturing facilities, we currently project that annual retail electricity sales in kWh will increase in the range of 1.0% to 3.0% for 2023 and that average annual growth will be in the range of 4.5% to 6.5% through 2025, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of several large data centers and new large manufacturing facilities, which are expected to contribute to average annual growth in the range of 3.5% to 5.5% through 2025. Lower projected sales growth for 2023 compared to our prior update is primarily due to slower-than-expected growth in new data center customers and delays among several new, large manufacturing facilities, as well as weaker usage among residential customers.

Longer term, APS has been preparing for and can serve significant load growth from residential and business customers. On top of these existing growth trends, APS is also now receiving unprecedented incremental requests for service from extra-large commercial energy users (over 25 MW) with very high energy demands that persist virtually around-the-clock. These incremental requests for service by extra-large energy users far exceed available generation and transmission resource capacity in the Southwest region for the foreseeable future. In April 2023, APS notified prospective extra-large customers without existing commitments from APS that it is not able to commit at this time to their future extra-large projects (over 25 MW) and that APS is exploring available options for securing sufficient electric generation and transmission to meet these projections of future customer needs.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Our experience indicates that typical variations from normal weather can result in increases and decreases in annual net income of up to $15 million; however, extreme weather variations have resulted in larger annual variations in net income.

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

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, unplanned outages, planned outages (typically scheduled in the spring and fall), renewable energy and DSM 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 "Liquidity and Capital Resources" below for information regarding the planned additions to our facilities.

Pension and Other Postretirement Non-Service Credits, Net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, the mortality assumptions and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

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 10.0% of the assessed value for 2023, 10.2% for 2022 and 10.7% for 2021. We expect property taxes to increase in 2023 due to higher plant balances related to expansion and improvements on our existing generation, transmission, and distribution facilities; partially offset by legislative changes reducing both property tax assessment ratios and rates in Arizona.

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. On December 22, 2017, the Tax Cuts and Jobs Act (the "Tax Act") was enacted and was generally effective on January 1, 2018. Changes impacting the Company include a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utilities, and requirements that certain excess deferred tax amounts of regulated utilities be normalized. See Note 4 for details of the impacts on the Company as of December 31, 2022. In APS's 2017 Rate Case Decision, the ACC approved the TEAM, which was being used to pass through the income tax effects to retail customers of the Tax Act. As part of the 2019 Rate Case (defined above), all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case. See Note 4 for details of the TEAM.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. See Note 3 for further details. 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 sales supplied under traditional cost-based rate regulation) and related activities and includes electricity generation, transmission and distribution.

Operating Results — Three-month period ended September 30, 2023, compared with three-month period ended September 30, 2022.

Our consolidated net income attributable to common shareholders for the three months ended September 30, 2023, was $398 million, compared with consolidated net income attributable to common shareholders of $326 million for the prior-year period. The results reflect an increase of approximately $65 million for the regulated electricity segment, primarily as a result of the effects of weather, CRS and LFCR revenue and other income. These positive factors were partially offset by higher interest charges, net of AFUDC, lower pension and other postretirement non-service credits, and higher depreciation and amortization expense mostly due to increased plant assets.

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

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 1,023	$ 913	$ 110
Operations and maintenance	(250)	(250)	—
Depreciation and amortization	(204)	(191)	(13)
Taxes other than income taxes	(53)	(53)	—
Pension and other postretirement non-service credits - net	10	25	(15)
Other income and expenses, net	16	4	12
Interest charges, net of allowance for borrowed funds used during construction	(88)	(63)	(25)
Income taxes	(57)	(53)	(4)
Less income related to noncontrolling interests (Note 6)	(4)	(4)	—
Regulated electricity segment income	393	328	65
All other	5	(2)	7
Net Income Attributable to Common Shareholders	$ 398	$ 326	$ 72

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $110 million higher for the three months ended September 30, 2023, 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	$ 78	$ 20	$ 58
CRS revenue (Note 4)	22	—	22
LFCR revenue (Note 4)	22	—	22
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	46	40	6
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	5	(1)	6
Lower transmission revenues (Note 4)	(4)	—	(4)
Retail revenue due to changes in usage patterns and impacts of energy efficiency and distributed generation, mostly offset by higher customer growth	(2)	(1)	(1)
Miscellaneous items, net	1	—	1
Total	$ 168	$ 58	$ 110

Operations and maintenance. Operations and maintenance expenses remained flat for the three months ended September 30, 2023, compared with the prior-year period primarily because of:

- A decrease of $19 million related to employee benefits;
- An increase of $6 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- An increase of $4 million related to non-nuclear generation costs primarily due to higher operating costs and higher planned outages;
- An increase of $4 million related to transmission, distribution, customer service and other miscellaneous factors;
- An increase of $3 million in nuclear generation costs;
- An increase of $2 million related to information technology costs.

Depreciation and amortization. Depreciation and amortization expenses were $13 million higher for the three months ended September 30, 2023, compared to the prior-year period primarily due to increased plant in service.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $15 million lower for the three months ended September 30, 2023, compared to the prior-year period primarily due to the effect of higher discount rates and actual market returns being lower than estimated returns in 2022.

Other income and expenses, net. Other income and expenses, net were $12 million higher for the three months ended September 30, 2023, compared to the prior-year period primarily due to higher interest income and higher allowance for equity funds used during construction due to increased capital expenditures.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, were $25 million higher for the three months ended September 30, 2023, compared to the prior-year period primarily due to higher debt balances and higher interest rates in the current period, partially offset by higher allowance for borrowed funds due to increased capital expenditures.

Income taxes. Income taxes were $4 million higher for the three months ended September 30, 2023, compared with the prior-year period primarily due to increased income tax expense resulting from higher pre-tax income, which was partially offset by the timing of when on-going permanent tax items and credits are recognized through the effective tax rate, and Investment Tax Credit amortization from our Arizona Sun battery facilities, as well as and Production Tax Credits from our Agave Solar facility, both of which went into service in 2023.

All Other. All other items were $7 million higher for the three months ended September 30, 2023, compared with the prior-year period primarily due to the gain on the BCE Sale. See Note 16.

Operating Results — Nine-month period ended September 30, 2023, compared with nine-month period ended September 30, 2022.

Our consolidated net income attributable to common shareholders for the nine months ended September 30, 2023, was $502 million, compared with consolidated net income attributable to common shareholders of $508 million for the prior-year period. The results reflect a decrease of approximately $11 million for the regulated electricity segment, primarily as a result of higher operations and maintenance expense, higher interest charges, lower pension and other postretirement non-service credits, and higher depreciation and amortization expense mostly due to increased plant assets. These negative factors were partially offset by higher LFCR revenue, the effects of weather, higher other income, CRS revenue, and transmission revenue, and lower income taxes.

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

	Nine Months Ended September 30,		
	2023	2022	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,286	$ 2,137	$ 149
Operations and maintenance	(774)	(712)	(62)
Depreciation and amortization	(590)	(563)	(27)
Taxes other than income taxes	(168)	(165)	(3)
Pension and other postretirement non-service credits - net	30	74	(44)
Other income and expenses, net	49	25	24
Interest charges, net of allowance for borrowed funds used during construction	(245)	(187)	(58)
Income taxes	(74)	(84)	10
Less income related to noncontrolling interests (Note 6)	(13)	(13)	—
Regulated electricity segment income	501	512	(11)
All other	1	(4)	5
Net Income Attributable to Common Shareholders	$ 502	$ 508	$ (6)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $149 million higher for the nine months ended September 30, 2023, 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)		
LFCR revenue (Note 4)	$ 41	$ —	$ 41
Effects of weather	45	12	33
CRS revenue (Note 4)	22	—	22
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	14	(6)	20
Higher transmission revenues (Note 4)	12	—	12
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	241	231	10
Higher retail revenue due to customer growth and changes in customer usage patterns, partially offset by the impacts of energy efficiency and distributed generation	14	6	8
Miscellaneous items, net	3	—	3
Total	$ 392	$ 243	$ 149

Operations and maintenance. Operations and maintenance expenses increased $62 million for the nine months ended September 30, 2023, compared with the prior-year period primarily because of:

- An increase of $26 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- An increase of $25 million related to non-nuclear generation costs primarily due to higher operating costs and higher planned outages;
- An increase of $12 million related to nuclear generation costs;
- An increase of $10 million related to transmission, distribution, and customer service;
- An increase of $8 million related to information technology costs;
- A decrease of $28 million related to employee benefits largely due to decreased pension and other post-retirement service costs of $11 million and other miscellaneous factors. See “pension and other postretirement non-service credits, net” below for additional discussion; and
- An increase of $9 million for corporate resources and other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $27 million higher for the nine months ended September 30, 2023, compared to the prior-year period primarily due to increased plant in service.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $44 million lower for the nine months ended September 30, 2023, compared to the prior-year period primarily due to the effect of higher discount rates and actual market returns being lower than estimated returns in 2022.

Other income and expenses, net. Other income and expenses, net were $24 million higher for the nine months ended September 30, 2023, compared to the prior-year period primarily due to higher interest income and higher allowance for equity funds used during construction due to increased capital expenditures.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, were $58 million higher for the nine months ended September 30, 2023, compared to the prior-year period primarily due to higher debt balances, higher commercial paper balances and higher interest rates in the current period, partially offset by higher allowance for borrowed funds due to increased capital expenditures.

Income taxes. Income taxes were $10 million lower for the nine months ended September 30, 2023, compared with the prior-year period primarily due to Investment Tax Credit amortization from our Arizona Sun battery facilities, and Production Tax Credits from our Agave Solar facility, both of which went into service in 2023.

All Other. All other items were $5 million higher for the nine months ended September 30, 2023, compared with the prior-year period primarily due to the gain on the BCE Sale. See Note 16.

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 September 30, 2023, APS's common equity ratio, as defined, was 50%. Its total shareholder equity was approximately $7.4 billion and total capitalization was approximately $14.9 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $6.0 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.

Dividends to Pinnacle West from APS are also dependent on a number of factors including, among others, APS's financial condition and free cash flow, the sources of which vary from quarter-to-quarter due in part to the seasonal nature of electricity demand. APS's sources of cash include cash from operations and external sources of liquidity including long- and short-term external debt financing such as commercial paper and its revolving credit facility. 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.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities (dollars in millions):

Pinnacle West Consolidated

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	Net Change
Net cash flow provided by operating activities	$ 834	$ 1,032	$ (198)
Net cash flow used for investing activities	(1,236)	(1,222)	(14)
Net cash flow provided by financing activities	412	187	225
Net change in cash and cash equivalents	$ 10	$ (3)	$ 13

Arizona Public Service Company

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	Net Change
Net cash flow provided by operating activities	$ 890	$ 1,040	$ (150)
Net cash flow used for investing activities	(1,227)	(1,188)	(39)
Net cash flow provided by financing activities	347	144	203
Net change in cash and cash equivalents	$ 10	$ (4)	$ 14

Operating Cash Flows

Nine-month period ended September 30, 2023, compared with nine-month period ended September 30, 2022. Pinnacle West's consolidated net cash provided by operating activities was $834 million in 2023, compared to $1,032 million in 2022, a decrease of $198 million in net cash provided primarily due to $359 million higher fuel and purchased power costs, $177 million higher payments for operations and maintenance costs, $45 million higher interest payments and $13 million change in net collateral, partially offset by $379 million higher cash receipts from electric revenues and $17 million other 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. Pinnacle West also sponsors other postretirement benefit plans for the employees of Pinnacle West and its 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. Under ERISA, the qualified pension plan was 112% funded as of January 1, 2023, and 139% as of January 1, 2022. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We have not made any voluntary contributions to our pension plan year-to-date in 2023. The minimum required contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary contributions in 2023, 2024 or 2025. With regard to contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2023 and do not expect to make any contributions in 2023, 2024 or 2025. We continually monitor financial market volatility and its impact on our retirement plans and other postretirement benefits, but we believe our liability driven investment strategy helps to minimize the impact of market volatility on our plan's funded status. For instance, our pension plan's funded status, as measured for accounting principles generally accepted in the United States of America ("GAAP") purposes, was 106% funded as of December 31, 2022, and our postretirement benefit plans were 159% funded, as measured for GAAP purposes at December 31, 2022. See Note 5 for additional details.

The CARES Act allowed employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020, which was approximately $18 million. As of December 31, 2022, we have paid this cash deferral in full.

Investing Cash Flows

Nine-month period ended September 30, 2023, compared with nine-month period ended September 30, 2022. Pinnacle West's consolidated net cash used for investing activities was $1,236 million in 2023, compared to $1,222 million in 2022, an increase of $14 million primarily related to increased capital expenditures and higher allowance for borrowed funds, partially offset by proceeds from the BCE sale. The difference between APS's and Pinnacle West's net cash used for investing activities primarily relates to the BCE Sale.

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

Capital Expenditures
(dollars in millions)

	2023	2024	2025
APS			
Generation:			
Clean:			
Nuclear Generation	$ 125	$ 120	$ 120
Renewables and Energy Storage Systems ("ESS") (a)	200	345	400
Other Generation (b)	305	245	245
Distribution	590	530	530
Transmission	315	300	300
Other (c)	265	260	255
Total APS	$ 1,800	$ 1,800	$ 1,850

(a) APS Solar Communities program, energy storage, renewable projects, and other clean energy projects.
(b) Includes generation environmental projects.
(c) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various additions and improvements to APS's clean resources, including nuclear plants, renewables and ESS. Generation capital expenditures also include additions and improvements to existing fossil plants. Examples of the types of projects included in the forecast of generation capital expenditures are additions of renewables and energy storage, and upgrades and capital replacements of various nuclear and fossil power plant equipment, such as turbines, boilers, and environmental equipment. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

Nine-month period ended September 30, 2023, compared with nine-month period ended September 30, 2022. Pinnacle West's consolidated net cash provided by financing activities was $412 million in 2023, compared to $187 million in 2022, an increase of $225 million in net cash provided primarily due to $234 million in higher issuance of long-term debt and $117 million lower long-term debt repayments, partially offset by a net decrease in short-term borrowings of $118 million.

APS's consolidated net cash provided by financing activities was $347 million in 2023, compared to $144 million in 2022, an increase of $203 million in net cash provided primarily due to $368 million in higher issuance of long-term debt, partially offset by a net decrease in short-term borrowings of $159 million.

Significant Financing Activities. On October 18, 2023, the Pinnacle West Board of Directors declared a dividend of $0.88 per share of common stock, payable on December 1, 2023, to shareholders of record on November 1, 2023. This represents an increase in the indicated annual dividend from $3.46 per share to $3.52 per share.

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, to finance indebtedness, and other general corporate purposes. See Note 3 for more information on available credit facilities.

Other Financing Matters. See Note 7 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 these covenants. For both Pinnacle West and APS, these covenants require that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At September 30, 2023, the ratio was approximately 58% for Pinnacle West and 51% 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 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.

On December 17, 2020, the ACC issued a financing order that, subject to specified parameters and procedures, increased APS's long-term debt limit, and authorized APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). On December 15, 2022, the ACC issued a financing order approving APS's application filed April 6, 2022 requesting to further increase the long-term debt limit from $7.5 billion to $8.0 billion and to exclude financing lease PPAs from the definition of long-term debt for purposes of the ACC financing orders. See Note 3 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of October 27, 2023, 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. 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 potential downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	Baa1	BBB+	BBB+
Senior unsecured	Baa1	BBB	BBB+
Commercial paper	P-2	A-2	F2
Outlook	Negative	Negative	Negative
APS			
Corporate credit rating	A3	BBB+	BBB+
Senior unsecured	A3	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Negative	Negative	Negative

Contractual Obligations

Pinnacle West has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Material contractual obligations and other commitments are as follows:

- Pinnacle West and APS have material long-term debt obligations that mature at various dates through 2050 and bear interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at September 30, 2023. See Note 3.

- Pinnacle West and APS maintain committed revolving credit facilities. See Note 3 for short-term debt details.

- Fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. See Notes 4 and 8. Purchase obligations includes capital expenditures and other obligations. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Note 8.

- APS holds certain contracts to purchase renewable energy credits in compliance with the RES. See Notes 4 and 8.

- APS is required to make payments to the noncontrolling interests related to the Palo Verde sale leaseback through 2033. See Note 6.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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 and estimates since our 2022 Form 10-K. See "Critical Accounting Policies" in Item 7 of the 2022 Form 10-K for further details about our critical accounting policies and estimates.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices, investments held by our nuclear decommissioning trusts, other special use funds 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 trusts, other special use funds (see Notes 11 and 12), and benefit plan assets. The nuclear decommissioning trusts, other special use funds 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 natural gas. 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 energy derivative positions (dollars in millions):

	Nine Months Ended September 30,	
	2023	2022
Mark-to-market of net positions at beginning of period	$ 96	$ 107
Increase (decrease) in regulatory liability	(130)	152
Mark-to-market of net positions at end of period	$ (34)	$ 259

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) at September 30, 2023, 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 2022 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2023	2024	2025	2026	2027	Total Fair Value
Observable prices provided by other external sources	$ (11)	$ (20)	$ (10)	$ —	$ —	$ (41)
Prices based on unobservable inputs	1	6	—	—	—	7
Total by maturity	$ (10)	$ (14)	$ (10)	$ —	$ —	$ (34)

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 (dollars in millions):

	September 30, 2023 Gain (Loss)		December 31, 2022 Gain (Loss)	
	Price Up 10%	**Price Down 10%**	**Price Up 10%**	**Price Down 10%**
Mark-to-market changes reported in:				
Regulatory asset (liability) (a)				
Electricity	$ 3	$ (3)	$ 12	$ (12)
Natural gas	58	(58)	55	(55)
Total	$ 61	$ (61)	$ 67	$ (67)

(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.

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 7 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 September 30, 2023. 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 September 30, 2023. 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 September 30, 2023, 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 2022 Form 10-K with regard to pending or threatened litigation and other matters.

See Note 4 for ACC and FERC-related matters.

See Note 8 for information regarding environmental matters, Superfund-related matters and other disputes.

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 2022 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 2022 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.

The risk factor below is an update to our 2022 Form 10-K.

The impact of wildfires could negatively affect APS's results of operations.

Wildfires have the potential to affect communities within APS's service territory and the surrounding areas, as well as APS's vast network of electric transmission and distribution lines and facilities. The potential likelihood of wildfires has increased due to many of the same weather and climate change impacts existing in Arizona as those that led to catastrophic wildfires in California. The continued expansion of the wildland urban interface has also increased wildfire risk to surrounding communities. While we proactively take steps to mitigate wildfire risk in the areas of our electrical assets, wildfire risk is always present due to APS's expansive service territory. APS could be held liable for damages incurred as a result of wildfires if it was determined that they were caused by or enhanced due to any fault of APS. Wildfires could also lead to volatility in the market price of our common stock and increased risks of our credit ratings being downgraded and significant financial distress. Furthermore, any damage caused to our assets, loss of service to our customers, or liability imposed as a result of wildfires could negatively impact APS's financial condition, results of operations, or cash flows.

Item 5. OTHER INFORMATION

Union Matters

Approximately 1,200 APS employees are union employees represented by the International Brotherhood of Electrical Workers ("IBEW"). On September 25, 2023, the IBEW membership ratified a new collective bargaining agreement ("CBA") with APS. The new CBA became effective in October 2023. This new contract has a duration of three years and becomes amendable on April 1, 2026.

Rule 10b5-1 Trading Plans

During the fiscal quarter ended September 30, 2023, none of our directors or executive officers adopted or terminated any contract, instruction or written plan for the purchase or sale of our securities to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement."

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
31.1	Pinnacle West	Certificate of Jeffrey B. Guldner, 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 Andrew Cooper, 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 Jeffrey B. Guldner, 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 Andrew Cooper, 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 - the instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL 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
104	Pinnacle West APS	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*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 February 19, 2020	3.1 to Pinnacle West/APS February 25, 2020 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/25/2020
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 Report, 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: November 2, 2023

By: /s/ Andrew Cooper
Andrew Cooper
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: November 2, 2023

By: /s/ Andrew Cooper
Andrew Cooper
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)