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 March 31, 2024

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 April 25, 2024:	113,558,885
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of April 25, 2024:	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, 2023 ("2023 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:

- uncertainties associated with the current and future economic environment, including economic growth rates, labor market conditions, 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 our 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 facilities 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 2023 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 March 31,	
	2024	**2023**
OPERATING REVENUES (Note 2)	$951,712	$944,955
OPERATING EXPENSES		
Fuel and purchased power	357,864	394,504
Operations and maintenance	257,578	250,080
Depreciation and amortization	210,294	191,906
Taxes other than income taxes	59,164	57,138
Other expense	20	610
Total	884,920	894,238
OPERATING INCOME	66,792	50,717
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	10,292	15,061
Pension and other postretirement non-service credits - net (Note 5)	11,568	9,865
Other income (Note 9)	30,607	6,077
Other expense (Note 9)	(7,567)	(4,131)
Total	44,900	26,872
INTEREST EXPENSE		
Interest charges	99,774	88,119
Allowance for borrowed funds used during construction	(13,141)	(12,722)
Total	86,633	75,397
Income Before Income Taxes	25,059	2,192
Income Taxes	3,891	1,183
Net Income	21,168	1,009
Less: Net income attributable to noncontrolling interests (Note 6)	4,306	4,306
Net Income (Loss) Attributable to Common Shareholders	$ 16,862	$ (3,297)
Weighted-average common shares outstanding - basic	113,621	113,358
Weighted-average common shares outstanding - diluted	114,227	113,358
Earnings Per Weighted-Average Common Share Outstanding		
Net income (loss) attributable to common shareholders - basic	$ 0.15	$ (0.03)
Net income (loss) attributable to common shareholders - diluted	$ 0.15	$ (0.03)

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 March 31,	
	2024	2023
NET INCOME	$ 21,168	$ 1,009
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX		
Derivative instruments net unrealized loss, net of tax benefit of $— and $202	—	(616)
Pension and other postretirement benefit activity, net of tax expense of $185 and $169	562	515
Total other comprehensive income (loss)	562	(101)
COMPREHENSIVE INCOME	21,730	908
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,306
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 17,424	$ (3,398)

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

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

	March 31, 2024	December 31, 2023
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,634	$ 4,955
Customer and other receivables	425,716	513,892
Accrued unbilled revenues	166,479	167,553
Allowance for doubtful accounts (Note 2)	(19,224)	(22,433)
Materials and supplies (at average cost)	438,943	444,344
Income tax receivable	—	332
Fossil fuel (at average cost)	50,230	49,203
Assets from risk management activities (Note 7)	78	6,808
Assets held for sale (Note 14)	—	35,139
Deferred fuel and purchased power regulatory asset (Note 4)	387,737	463,195
Other regulatory assets (Note 4)	191,132	162,562
Other current assets	131,257	101,417
Total current assets	1,781,982	1,926,967
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,239,024	1,201,246
Other special use funds (Notes 11 and 12)	364,225	362,781
Other assets	106,830	102,845
Total investments and other assets	1,710,079	1,666,872
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	24,461,914	24,211,167
Accumulated depreciation and amortization	(8,594,795)	(8,408,040)
Net	15,867,119	15,803,127
Construction work in progress	1,685,365	1,724,004
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	85,459	86,426
Intangible assets, net of accumulated amortization	512,874	267,110
Nuclear fuel, net of accumulated amortization	113,825	99,490
Total property, plant and equipment	18,264,642	17,980,157
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,371,260	1,390,279
Operating lease right-of-use assets	1,325,138	1,309,975
Assets for pension and other postretirement benefits (Note 5)	334,765	323,438
Other	59,847	63,465
Total deferred debits	3,091,010	3,087,157
TOTAL ASSETS	$ 24,847,713	$ 24,661,153

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

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

	March 31, 2024	December 31, 2023
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 476,629	$ 442,455
Accrued taxes	224,851	166,833
Accrued interest	74,001	72,916
Common dividends payable	—	99,813
Short-term borrowings (Note 3)	793,500	609,500
Current maturities of long-term debt (Note 3)	875,000	875,000
Customer deposits	42,059	42,037
Liabilities from risk management activities (Note 7)	113,530	80,913
Liabilities for asset retirements	33,048	28,550
Operating lease liabilities	69,102	67,883
Regulatory liabilities (Note 4)	221,552	209,923
Other current liabilities	132,597	193,524
Total current liabilities	3,055,869	2,889,347
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	7,541,871	7,540,622
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,396,743	2,416,480
Regulatory liabilities (Note 4)	1,966,120	1,965,865
Liabilities for asset retirements	946,457	937,451
Liabilities for pension benefits (Note 5)	110,597	112,702
Liabilities from risk management activities (Note 7)	34,872	42,975
Customer advances	533,180	533,580
Coal mine reclamation	185,229	184,007
Deferred investment tax credit	257,448	257,743
Unrecognized tax benefits	34,511	33,861
Operating lease liabilities	1,225,468	1,210,189
Other	248,815	251,469
Total deferred credits and other	7,939,440	7,946,322
COMMITMENTS AND CONTINGENCIES (Note 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 113,686,849 and 113,537,689 issued at respective dates	2,757,506	2,752,676
Treasury stock at cost; 128,234 and 113,272 shares at respective dates	(9,073)	(8,185)
Total common stock	2,748,433	2,744,491
Retained earnings	3,483,178	3,466,317
Accumulated other comprehensive loss (Note 13)	(32,582)	(33,144)
Total shareholders’ equity	6,199,029	6,177,664
Noncontrolling interests (Note 6)	111,504	107,198
Total equity	6,310,533	6,284,862
TOTAL LIABILITIES AND EQUITY	$24,847,713	$24,661,153

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)

	Three Months Ended March 31,	
	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 21,168	$ 1,009
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale relating to BCE	(22,988)	—
Depreciation and amortization including nuclear fuel	226,413	208,772
Deferred fuel and purchased power	(33,094)	(90,305)
Deferred fuel and purchased power amortization	108,552	80,904
Allowance for equity funds used during construction	(10,292)	(15,061)
Deferred income taxes	(23,297)	(5,150)
Deferred investment tax credit	(294)	3,749
Change in derivative instruments fair value	—	786
Stock compensation	5,935	3,635
Changes in current assets and liabilities:		
Customer and other receivables	84,888	2,831
Accrued unbilled revenues	1,074	21,488
Materials, supplies and fossil fuel	4,374	(14,392)
Income tax receivable	332	2,387
Other current assets	(32,306)	(8,099)
Accounts payable	23,799	(69,576)
Accrued taxes	58,018	50,044
Other current liabilities	(55,343)	(84,003)
Change in long-term regulatory assets	9,850	14,557
Change in long-term regulatory liabilities	16,493	33,555
Change in other long-term assets	(19,571)	(72,593)
Change in operating lease assets	(8,416)	(8,920)
Change in other long-term liabilities	(17,489)	104,858
Change in operating lease liabilities	9,547	51,129
Net cash provided by operating activities	347,353	211,605
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(517,756)	(445,171)
Contributions in aid of construction	69,047	25,165
Proceeds from sale relating to BCE	38,681	—
Allowance for borrowed funds used during construction	(13,141)	(12,722)
Proceeds from nuclear decommissioning trust sales and other special use funds	443,870	226,626
Investment in nuclear decommissioning trust and other special use funds	(443,854)	(227,196)
Other	(939)	(19,941)
Net cash used for investing activities	(424,092)	(453,239)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	—	185,136
Short-term borrowing and (repayments) - net	184,000	156,830
Dividends paid on common stock	(98,082)	(96,078)

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 March 31, 2024							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2023	113,537,689	$2,752,676	(113,272)	$(8,185)	$3,466,317	$ (33,144)	$ 107,198	$6,284,862
Net income		—		—	16,862	—	4,306	21,168
Other comprehensive income		—		—	—	562	—	562
Issuance of common stock (a)	149,160	4,830		—	—	—	—	4,830
Purchase of treasury stock (b)		—	(71,008)	(4,907)	—	—	—	(4,907)
Reissuance of treasury stock for stock-based compensation and other		—	56,046	4,018	—	—	—	4,018
Other		—		1	(1)	—	—	—
Balance, March 31, 2024	113,686,849	$2,757,506	(128,234)	$(9,073)	$3,483,178	$ (32,582)	$ 111,504	$6,310,533

	Three Months Ended March 31, 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		—		—	(3,297)	—	4,306	1,009
Other comprehensive loss		—		—	—	(101)	—	(101)
Issuance of common stock	112,278	6,111		—	—	—	—	6,111
Purchase of treasury stock (b)		—	(33,154)	(2,490)	—	—	—	(2,490)
Reissuance of treasury stock for stock-based compensation and other		—	626	44	—	—	—	44
Other		—		—	2	—	—	2
Balance, March 31, 2023	113,359,467	$2,730,851	(106,141)	$(7,451)	$3,357,052	$ (31,536)	$ 115,535	$6,164,451

(a) See Note 10 for information related to our equity forward sale agreements that were executed in February 2024. As of March 31, 2024, no common shares have been issued as part of this agreement.

(b) 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 March 31,	
	2024	2023
OPERATING REVENUES (Note 2)	$951,712	$944,955
OPERATING EXPENSES		
Fuel and purchased power	357,864	394,504
Operations and maintenance	253,593	246,179
Depreciation and amortization	210,273	191,884
Taxes other than income taxes	59,078	57,125
Other expense	20	610
Total	880,828	890,302
OPERATING INCOME	70,884	54,653
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	10,292	15,061
Pension and other postretirement non-service credits - net (Note 5)	11,773	10,106
Other income (Note 9)	6,855	5,075
Other expense (Note 9)	(2,894)	(2,617)
Total	26,026	27,625
INTEREST EXPENSE		
Interest charges	86,979	75,222
Allowance for borrowed funds used during construction	(13,141)	(11,157)
Total	73,838	64,065
INCOME BEFORE INCOME TAXES	23,072	18,213
INCOME TAXES	3,649	3,247
NET INCOME	19,423	14,966
Less: Net income attributable to noncontrolling interests (Note 6)	4,306	4,306
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 15,117	$ 10,660

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 March 31,	
	2024	2023
NET INCOME	$ 19,423	$ 14,966
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Pension and other postretirement benefits activity, net of tax expense of $161 and $150	490	457
Total other comprehensive income	490	457
COMPREHENSIVE INCOME	19,913	15,423
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,306
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 15,607	$ 11,117

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

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

	March 31, 2024	December 31, 2023
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$24,458,518	$24,207,706
Accumulated depreciation and amortization	(8,591,536)	(8,404,721)
Net	15,866,982	15,802,985
Construction work in progress	1,685,365	1,724,004
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	85,459	86,426
Intangible assets, net of accumulated amortization	512,719	266,955
Nuclear fuel, net of accumulated amortization	113,825	99,490
Total property, plant and equipment	18,264,350	17,979,860
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,239,024	1,201,246
Other special use funds (Notes 11 and 12)	364,225	362,781
Other assets	43,676	43,625
Total investments and other assets	1,646,925	1,607,652
CURRENT ASSETS		
Cash and cash equivalents	9,494	4,549
Customer and other receivables	422,651	510,296
Accrued unbilled revenues	166,479	167,553
Allowance for doubtful accounts (Note 2)	(19,224)	(22,433)
Materials and supplies (at average cost)	438,943	444,344
Fossil fuel (at average cost)	50,230	49,203
Assets from risk management activities (Note 7)	78	6,808
Deferred fuel and purchased power regulatory asset (Note 4)	387,737	463,195
Other regulatory assets (Note 4)	191,132	162,562
Other current assets	76,154	64,311
Total current assets	1,723,674	1,850,388
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,371,260	1,390,279
Operating lease right-of-use assets	1,323,837	1,308,611
Assets for pension and other postretirement benefits (Note 5)	327,836	316,606
Other	59,447	63,059
Total deferred debits	3,082,380	3,078,555
TOTAL ASSETS	$24,717,329	$24,516,455

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

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

	March 31, 2024	December 31, 2023
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	3,321,696	3,321,696
Retained earnings	3,774,414	3,759,299
Accumulated other comprehensive loss (Note 13)	(16,729)	(17,219)
Total shareholder equity	7,257,543	7,241,938
Noncontrolling interests (Note 6)	111,504	107,198
Total equity	7,369,047	7,349,136
Long-term debt less current maturities (Note 3)	7,042,930	7,041,891
Total capitalization	14,411,977	14,391,027
CURRENT LIABILITIES		
Short-term borrowings (Note 3)	733,500	532,850
Current maturities of long-term debt (Note 3)	250,000	250,000
Accounts payable	470,973	433,229
Accrued taxes	222,033	162,288
Accrued interest	71,988	72,548
Common dividends payable	—	99,800
Customer deposits	42,059	42,037
Liabilities from risk management activities (Note 7)	113,530	80,913
Liabilities for asset retirements	33,048	28,550
Operating lease liabilities	68,878	67,608
Regulatory liabilities (Note 4)	221,552	209,923
Other current liabilities	125,305	211,773
Total current liabilities	2,352,866	2,191,519
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,434,844	2,431,697
Regulatory liabilities (Note 4)	1,966,120	1,965,865
Liabilities for asset retirements	946,457	937,451
Liabilities for pension benefits (Note 5)	104,669	106,215
Liabilities from risk management activities (Note 7)	34,872	42,975
Customer advances	533,180	533,580
Coal mine reclamation	185,229	184,007
Deferred investment tax credit	257,448	257,743
Unrecognized tax benefits	37,007	33,861
Operating lease liabilities	1,224,170	1,208,857
Other	228,490	231,658
Total deferred credits and other	7,952,486	7,933,909
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL LIABILITIES AND EQUITY	$24,717,329	$24,516,455

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)

	Three Months Ended March 31,	
	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 19,423	$ 14,966
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	226,392	208,750
Deferred fuel and purchased power	(33,094)	(90,305)
Deferred fuel and purchased power amortization	108,552	80,904
Allowance for equity funds used during construction	(10,292)	(15,061)
Deferred income taxes	2,071	(1,693)
Deferred investment tax credit	(294)	3,749
Changes in current assets and liabilities:		
Customer and other receivables	84,357	9,347
Accrued unbilled revenues	1,074	21,488
Materials, supplies and fossil fuel	4,374	(14,392)
Other current assets	3,516	(11,039)
Accounts payable	26,328	(64,008)
Accrued taxes	59,745	55,194
Other current liabilities	(82,478)	(82,422)
Change in long-term regulatory assets	9,850	14,557
Change in long-term regulatory liabilities	16,493	33,555
Change in other long-term assets	(51,555)	(70,466)
Change in operating lease assets	(8,479)	(8,998)
Change in other long-term liabilities	(19,584)	104,303
Change in operating lease liabilities	9,581	51,212
Net cash provided by operating activities	365,980	239,641
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(517,756)	(439,647)
Contributions in aid of construction	69,047	25,165
Allowance for borrowed funds used during construction	(13,141)	(11,157)
Proceeds from nuclear decommissioning trust sales and other special use funds	443,870	226,626
Investment in nuclear decommissioning trust and other special use funds	(443,854)	(227,196)
Other	(51)	(926)
Net cash used for investing activities	(461,885)	(427,135)
CASH FLOWS FROM FINANCING ACTIVITIES		
Short-term borrowings and (repayments) - net	200,650	138,000
Equity infusion	—	150,000
Dividends paid on common stock	(99,800)	(97,900)
Net cash provided by financing activities	100,850	190,100
NET INCREASE IN CASH AND CASH EQUIVALENTS	4,945	2,606
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,549	4,042
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 9,494	$ 6,648

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

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

	Three Months Ended March 31, 2024						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2023	71,264,947	$178,162	$3,321,696	$3,759,299	$ (17,219)	$ 107,198	$7,349,136
Net income		—	—	15,117	—	4,306	19,423
Other comprehensive income		—	—	—	490	—	490
Other		—	—	(2)	—	—	(2)
Balance, March 31, 2024	71,264,947	$178,162	$3,321,696	$3,774,414	$ (16,729)	$ 111,504	$7,369,047

	Three Months Ended March 31, 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		—	—	10,660	—	4,306	14,966
Other comprehensive income		—	—	—	457	—	457
Other		—	—	1	—	—	1
Balance, March 31, 2023	71,264,947	$178,162	$3,321,696	$3,618,125	$ (15,139)	$ 115,535	$7,218,379

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, El Dorado Investment Company ("El Dorado"), and Pinnacle West Power, LLC ("PNW Power"). 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. PNW Power is a wholly-owned subsidiary that was created in September 2023 to hold certain investments in wind and transmission joint projects that were previously held in Bright Canyon Energy Corporation ("BCE"). See Note 14 for additional information. 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.

BCE was a Pinnacle West subsidiary that was formed in 2014. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which all of our equity interest in BCE was sold. The sale was completed on January 12, 2024. See Note 14 for more information relating to the sale of BCE.

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 2023 Form 10-K.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2024	2023
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ 20,970	$ (12)
Interest, net of amounts capitalized	83,974	62,241
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 217,684	$ 115,559
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	3,544	3,851
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	6,747	551,239
BCE Sale non-cash consideration (Note 14)	45,608	—

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

	Three Months Ended March 31,	
	2024	2023
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 73,035	$ 53,610
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 217,684	$ 112,219
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	3,544	3,851
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	6,747	551,239

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31,	
	2024	**2023**
Retail Electric Service		
Residential	$ 432,692	$ 409,724
Non-Residential	461,483	406,137
Wholesale Energy Sales	26,864	95,603
Transmission Services for Others	27,712	31,791
Other Sources	2,961	1,700
Total Operating Revenues	$ 951,712	$ 944,955

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 the U.S. Federal Energy Regulatory Commission ("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 months ended March 31, 2024 and 2023 were $943 million and $922 million, respectively.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three months ended March 31, 2024 and 2023, our revenues that do not qualify as revenue from contracts with customers were $9 million and $23 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 March 31, 2024 or December 31, 2023.

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):

	March 31, 2024	December 31, 2023
Allowance for doubtful accounts, balance at beginning of period	$ 22,433	$ 23,778
Bad debt expense	4,769	23,399
Actual write-offs	(7,978)	(24,744)
Allowance for doubtful accounts, balance at end of period	$ 19,224	$ 22,433

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31, 2024, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $60 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on March 31, 2024, was 5.47%.

On February 28, 2024, Pinnacle West entered into various equity forward sale agreements (the “Equity Forward Sale Agreements”), which may be settled with Pinnacle West common stock or cash. At March 31, 2024, Pinnacle West could have settled the Equity Forward Sale Agreements with the issuance of 11,240,601 shares of common stock, which would have provided cash liquidity to Pinnacle West of $728 million. See Note 10.

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 by 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. The 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 March 31, 2024, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $384 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on March 31, 2024, was 5.42%.

APS is currently authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking ACC approval. On October 27, 2023, APS sought approval from the ACC to receive from Pinnacle West in 2024 up to an additional $500 million in equity infusions above the authorized limit of $150 million, and on January 9, 2024, the ACC approved the increased equity infusion limit for 2024.

On December 15, 2022, the ACC issued a financing order reaffirming the previous 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) and approving APS's application filed April 6, 2022 requesting to increase the long-term debt limit from $7.5 billion to $8.0 billion and to exclude financing lease power purchase agreements ("PPAs") from the definition of long-term debt for purposes of the ACC financing orders.

On April 19, 2024, APS submitted an application to the ACC requesting to further increase the long-term debt limit from $8.0 billion to $9.5 billion and to increase Pinnacle West's permitted yearly equity infusions to equal up to 2.5% of Pinnacle West's consolidated assets each calendar year on a three-year rolling average basis. APS cannot predict the outcome of this matter.

On December 12, 2023, APS entered into an agreement for a new 364-day $350 million term loan facility that matures on December 10, 2024. Borrowings under the facility bear interest at SOFR plus 1.0% per annum. On February 9, 2024, APS drew the full amount of $350 million.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 14. 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, Pinnacle West paid in full the outstanding $31 million equity bridge loan balance. As of March 31, 2024, and December 31, 2023, there was no outstanding balance on our Condensed Consolidated Balance Sheets relating to this credit agreement.

Pinnacle West has issued performance guarantees relating to BCE’s Kūpono solar project (the “Kūpono Solar Project”). BCE held an equity method investment in the Kūpono Solar Project. As a result of the BCE Sale that closed on January 12, 2024, Pinnacle West no longer holds an equity or ownership interest in BCE or the Kūpono Solar Project. The performance guarantees did not transfer in the BCE Sale, and Pinnacle West continues to retain these guarantees. 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):

	As of March 31, 2024		As of December 31, 2023	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$1,123,941	$1,099,455	$1,123,731	$1,095,935
APS	7,292,930	6,368,753	7,291,891	6,459,718
Total	$8,416,871	$7,468,208	$8,415,622	$7,555,653

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 would have represented 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 would have been an increase of 13.6%.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The principal provisions of APS's application were:

- 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 ("DSM") 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.

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 recommended, 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 recommended, 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 were:

- 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 Power Plant ("Four Corners") Effluent Limitation Guidelines ("ELG") project;

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- 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.

On November 6, 2023, and November 21, 2023, APS and stakeholders filed briefs in the 2022 Rate Case. APS's briefs included the reduction of the total revenue requirement increase to $376.2 million and a resulting average annual customer bill impact increase of 11.1%. All other major provisions from APS's rejoinder testimony were maintained in its briefs. ACC Staff's briefs included a proposed total revenue requirement increase from $281.9 million to $282.7 million and also included their support of APS's SRB mechanism, contingent on increased stakeholder outreach.

On January 25, 2024, an Administrative Law Judge issued a Recommended Opinion and Order in the 2022 Rate Case, as corrected on February 6, 2024 (the "2022 Rate Case ROO"). The 2022 Rate Case ROO recommended, among other things, (i) a $523.1 million increase in the annual base rate revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.36%, (v) 12 months of post-test year plant and the inclusion of the Four Corners ELG project, (vi) the approval of APS's SRB proposal with certain procedural and other modifications, (vii) no additional CCT funding, (viii) a 5.0%

return on the prepaid pension asset and a return of 5.35% on the OPEB liability, and (ix) no disallowances on APS's coal contracts.

The 2022 Rate Case ROO also recommended a number of changes to existing adjustors, including (i) the approval of modified DSM performance incentives and the requested DSM transfer to base rates, (ii) the retention of $1.9 million of REAC in the adjustor rather than base rates, (iii) a partial transfer of $27.1 million of LFCR funds to base rates, and (iv) the adoption of an increase in the annual PSA cap to $0.006/kWh.

On February 22, 2024, the ACC approved a number of amendments to the 2022 Rate Case ROO that resulted in, among other things, (i) an approximately $491.7 million increase in the annual base revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.39%, (v) a return set at the Company's weighted average cost of capital on the net prepaid pension asset and net other post-employment benefit liability in rate base, (vi) an adjustment to generation maintenance and outage expense to reflect a more reasonable level of test year costs, (vii) approval of the SRB mechanism with modifications to customer notifications, procedural timelines and the inclusion of any qualifying technology and fuel source bid received through an all-source request for proposal (“RFP”), and (viii) recovery of all DSM costs through the DSMAC rather than through base rates.

The ACC’s decision results in an expected total net annual revenue increase for APS of approximately $253.4 million and a roughly 8% increase to the typical residential customer’s bill. The ACC issued the final order for the 2022 Rate Case on March 5, 2024, with the new rates becoming effective for all service rendered on or after March 8, 2024.

Six intervenors and the Attorney General of Arizona requested rehearing on various issues included in the ACC’s decision, such as the grid access charge (“GAC”) for solar customers, the SRB, and CCT funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, Arizona Solar Energy Industries Association, Solar Energy Industries Association, and Vote Solar for the limited purpose of reviewing arguments concerning the GAC. Specifically, rehearing is ordered as to whether the GAC rate is just and reasonable, including whether it should be higher or lower, whether the GAC rate constitutes a discriminatory fee to solar customers, and whether omission of a GAC charge is discriminatory to non-solar customers. All other applications for rehearing were denied. The parties seeking rehearing have 30 days after the denial or granting of a request for rehearing to file a notice of appeal to the Arizona Court of Appeals. A procedural conference was held on April 26, 2024 for the purpose of discussing the procedural schedule for the matter. APS cannot predict the outcome of any subsequent proceedings.

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.

On November 2, 2021, the ACC approved the 2019 Rate Case ROO, with various amendments, that resulted in, among other things, (i) a return on equity of 8.70%, which included 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 selective catalytic reduction (“SCR”) project, with the exception of $215.5 million (see “Four Corners SCR Cost Recovery” below); (iii) the CCT plan including 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; 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.

Consistent with the 2019 Rate Case decision, as of April 2024, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) $10 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) $1.5 million to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County communities for CCT and economic

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 February 22, 2024, the ACC voted to not approve any further CCT funding.

APS filed a Notice of Direct Appeal to the Arizona Court of Appeals on December 17, 2021 requesting review of certain aspects of the 2019 Rate Case. 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.

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. See "Court Resolution Surcharge" below for more information.

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. On February 22, 2024, the ACC voted to not approve any further CCT funding.

Regulatory Lag Docket

On January 5, 2023, the ACC opened a new docket to explore the possibility of modifications to the ACC's historical test year rules. The ACC requested comments from utilities and interested parties on ways to reduce regulatory lag, including alternative ratemaking structures such as future test years and hybrid test years. APS filed comments on June 1, 2023. On March 19, 2024, the ACC held a workshop to discuss modifying the state's rate case test year rules. Utilities, including APS, spoke about alternatives to the current rules that could reduce regulatory lag. The ACC plans to hold another workshop on this topic and has invited further comments from stakeholders. On April 19, 2024, a letter was filed to the docket by an ACC commissioner discussing the potential benefits of modifying test year rules, including the potentiality of

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offering utilities to choose the type of test year that best suits them. The letter also recommended that this issue be discussed at the next possible open meeting. APS cannot predict the outcome of this matter.

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 modifications of adjustment mechanisms in the 2022 Rate Case.

Renewable Energy Standard. In 2006, the ACC approved the renewable energy standard ("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.

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 Integrated Resource Plan ("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 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 requested 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 ACC'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. On March 5, 2024, the ACC ordered APS to not expand or extend the

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APS Solar Communities program. Consistent with that decision, the Solar Communities program has been discontinued and APS stopped enrolling new customers. APS will continue work on projects that were in the queue prior to that decision.

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 ACC-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.

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 Implementation 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 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 June 1, 2022, APS filed its 2023 Transportation Electrification Plan ("2023 TE Plan"). The 2023 TE Plan detailed APS's efforts to support transportation electrification in Arizona, including the Take Charge AZ Pilot Program and customer education and outreach related to transportation electrification. Subsequently, APS filed an amended 2023 TE Plan on November 30, 2022, that included a request for a $5 million budget. On December 12, 2023, the ACC approved the 2023 TE Plan without including the Take Charge AZ Program and its budget going forward, but allowed APS to complete projects already underway. Additionally, the ACC discontinued the residential EV SmartCharger rebate and approved modifications to the EV rate plan.

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 maintained the originally proposed budget of $88 million. Subsequent to filing the amended 2023 DSM Implementation Plan and prior to the ACC approving it, on November 30, 2023, APS filed its 2024 DSM Implementation Plan. The 2024 DSM Implementation Plan requested a total budget of $91.5 million and incorporated all elements of the amended 2023 DSM Implementation Plan as well as the 2024 TE Implementation Plan. On April 26, 2024, APS filed an amendment to the 2024 DSM Implementation Plan. The amended 2024 DSM Implementation Plan includes an updated budget to reflect removal of all incentive funds for the EV Charging Demand Management Pilot, an update on the performance incentive calculation, and the withdrawal of tranches two and three of the residential battery pilot. The ACC has not yet ruled on the amended 2024 DSM Implementation Plan. APS cannot predict the outcome of this proceeding.

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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 $0.006 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 2024 and 2023 (dollars in thousands):

	Three Months Ended March 31,	
	2024	**2023**
Beginning balance	$ 463,195	$ 460,561
Deferred fuel and purchased power costs — current period	33,094	90,305
Amounts charged to customers	(108,552)	(80,904)
Ending balance	$ 387,737	$ 469,962

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 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 contained 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 found that APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity were reasonable and appropriate. The report included 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.

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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. On November 30, 2023, APS notified the ACC that it will be maintaining the current PSA rate of $0.019074 per kWh and an updated PSA adjustment schedule would not be filed at that time. In Decision No. 79293 in the 2022 Rate Case, the ACC approved a permanent increase in the annual PSA adjustor rate cap from $0.004 per kWh to $0.006 per kWh and a requirement that APS report to the ACC for possible action when the overall PSA balance reaches $100 million. As part of the 2022 Rate Case decision, the ACC also approved an overall PSA rate of $0.011977 per kWh, which consisted of a forward component of $(0.012624) per kWh, a historical component of $0.013071 per kWh, and a transition component of $0.011530 per kWh. The rate became effective on March 8, 2024.

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. In 2023, nine energy storage PPAs and their respective costs have been approved for recovery through the PSA. In 2022, one energy storage PPA and its costs was approved for recovery through the PSA. In 2021, four energy storage PPAs and their respective costs were approved for recovery through the PSA. However, one energy storage PPA that was approved in 2021 was later terminated by APS due to project delays.

Environmental Improvement Surcharge. On March 5, 2024, the ACC approved the elimination of the EIS, and the surcharge is no longer in effect. The EIS permitted 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. APS's February 1, 2023 EIS 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; however, with the elimination of the surcharge, it is no longer in effect.

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, 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

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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, 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 distributed generation (“DG”) such as rooftop solar arrays. 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.

As a result of the 2019 Rate Case decision, the fixed costs recoverable by the LFCR mechanism were set at 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. APS's annual LFCR adjustor rate is dependent on an annual earnings test filing, which compares 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. As a result of certain changes made to the LFCR mechanism in the 2019 Rate Case decision, the mechanism no longer qualifies for alternative revenue program accounting treatment.

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 a $11.8 million balance from APS's 2021 LFCR 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 September 5, 2023, APS filed an updated LFCR Plan of Administration, which was approved by ACC Staff on December 8, 2023. 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). On October 19, 2023, a request for intervention was filed, which was granted. Consistent with an October 25, 2023, Procedural Order, the parties met and conferred and conducted limited discovery. As a result of Decision No. 79293 in the 2022 Rate Case, APS transferred $27.1 million from the LFCR to base rates.

On March 8, 2024, APS filed conforming LFCR schedules to incorporate changes required as a result of Decision No. 79293 in the 2022 Rate Case. On April 9, 2024, the ACC approved the 2023 annual LFCR adjustment, with new rates effective in the first billing cycle of May 2024.

Tax Expense Adjustor Mechanism. The TEAM helps 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. As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021. The TEAM was retained in the 2022 Rate Case 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 portion of the CRS representing the recovery of the $59.6 million of lost revenue between December of 2021 and June 20, 2023, $12.7 million of which has been collected as of March 31, 2024, will cease upon full collection of the lost revenue. Additionally, the CRS tariff was updated to remove the return on equity component and account for SCR-related depreciation and deferral adjustments approved in Decision No. 79293 in the 2022 Rate Case. See “2019 Retail Rate Case” above for more information.

Net Metering

The ACC’s decision from APS’s 2017 rate case (the “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 April 29, 2022, APS filed an application to decrease the RCP price from 9.4 cents per kWh, which had been in effect since October 1, 2021, 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.

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. As a result of the procedural conference, ACC Staff issued a request for information to investigate the issues related to this matter. A status conference was held on March 20, 2024, to determine if ACC Staff is prepared to present a recommendation on this matter at that time. Stakeholders provided responses to the ACC Staff’s request for information on March 21, 2024. Another status conference has been scheduled for May 20, 2024 to discuss next steps. The amounts APS pays customers for solar exports under its RCP rate rider could be affected by this docket. APS cannot predict the outcome of this matter.

Energy Modernization Plan

On May 26, 2023, the ACC opened a new docket to review articles within the Arizona Administrative Code related to Resource Planning, the Renewable Energy Standard and Tariff, and Electric Energy Efficiency Standards. On January 9, 2024, the ACC approved a rulemaking process for this matter. During the ACC Open Meeting on February 6, 2024, the ACC approved motions to direct ACC Staff to include recommendations to repeal the current Electric Energy Efficiency and Renewable Energy Standard rules during the rulemaking process. 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 time frame. 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. On January 31, 2024, stakeholders filed comments regarding the IRP and APS has until May 31, 2024 to respond to the stakeholders' comments. APS cannot predict the outcome of this matter. 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 ACC approval. APS sought 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. On January 9, 2024, the ACC approved the increased equity infusion limit for 2024.

On April 19, 2024, APS submitted a request to the ACC to permanently modify Pinnacle West's permitted yearly equity infusions to equal up to 2.5% of

Pinnacle West’s consolidated assets each calendar year on a three-year rolling average basis. APS cannot predict the outcome of this matter.

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

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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.

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 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.

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 U.S. 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. APS is allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $31.5 million as of March 31, 2024, 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, $40.6 million as of March 31, 2024, 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, $10.1 million as of March 31, 2024. 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	March 31, 2024	December 31, 2023
Pension	(a)	$ 686,379	$ 696,476
Deferred fuel and purchased power (b) (c)	2025	387,737	463,195
Income taxes — allowance for funds used during construction (“AFUDC”) equity	2054	189,211	189,058
Deferred fuel and purchased power — mark-to-market (Note 7)	2026	154,658	120,214
Ocotillo deferral	2034	125,908	128,636
SCR deferral (e)	2038	87,576	89,477
Retired power plant costs	2033	79,747	83,536
Lease incentives	(g)	54,543	46,615
Income taxes — investment tax credit basis adjustment	2056	36,017	34,230
Deferred compensation	2036	33,923	33,972
Deferred property taxes	2027	30,345	32,488
Palo Verde VIEs (Note 6)	2046	20,732	20,772
Active Union Medical Trust	(f)	13,809	12,747
Navajo coal reclamation	2026	10,139	10,883
Mead-Phoenix transmission line contributions in aid of construction (“CIAC”)	2050	8,633	8,716
Loss on reacquired debt	2038	7,644	7,965
Four Corners cost deferral	2024	5,903	7,922
Tax expense adjustor mechanism (b)	2031	5,026	5,190
FERC Transmission true up	2026	4,313	616
Power supply adjustor - interest	2025	3,105	19,416
Other	Various	4,781	3,912
Total regulatory assets (d)		$1,950,129	$2,016,036
Less: current regulatory assets		$ 578,869	$ 625,757
Total non-current regulatory assets		$1,371,260	$1,390,279

(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. The 2022 Rate Case decision allows for the full return on the pension asset in rate base. 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) See “Four Corners SCR Cost Recovery” discussion above.

(f) Collected in retail rates.

(g) Amortization periods vary based on specific terms of lease contract.

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

	Amortization Through	March 31, 2024	December 31, 2023
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 929,197	$ 930,344
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	214,466	214,667
Asset retirement obligations	2057	411,393	392,383
Other postretirement benefits	(c)	215,298	226,726
Removal costs	(d)	90,082	94,368
Income taxes — deferred investment tax credit	2056	68,442	68,521
Income taxes — change in rates	2053	60,589	60,667
Four Corners coal reclamation	2038	56,557	55,917
Renewable energy standard (b)	2024	51,001	43,251
Spent nuclear fuel	2027	31,552	33,154
Demand side management (b)	2024	20,905	14,374
Sundance maintenance	2031	20,763	19,989
Property tax deferral	2027	9,541	10,850
Tax expense adjustor mechanism (b)	2032	4,796	4,835
FERC transmission true up (b)	2026	—	1,869
Other	Various	3,090	3,873
Total regulatory liabilities		$2,187,672	$2,175,788
Less: current regulatory liabilities		$ 221,552	$ 209,923
Total non-current regulatory liabilities		$1,966,120	$1,965,865

(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) See Note 5.
(d) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.

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 March 31,		Three Months Ended March 31,	
	2024	2023	2024	2023
Service cost — benefits earned during the period	$10,631	$10,157	$ 2,459	$ 2,120
Non-service costs (credits):				
Interest cost on benefit obligation	37,236	38,362	5,613	5,673
Expected return on plan assets	(46,983)	(45,561)	(11,709)	(10,872)
Amortization of:				
Prior service credit (a)	—	—	(9,447)	(9,447)
Net actuarial loss/(gain)	10,944	9,713	(2,080)	(2,303)
Net periodic cost/(benefit)	$11,828	$12,671	$(15,164)	$(14,829)
Portion of cost/(benefit) charged to expense	$ 6,337	$ 7,227	$(11,306)	$(10,737)

(a) Prior-service costs or credits reflect the impact of modifications to the pension or postretirement plan benefits. The impact of these modifications is amortized over a period which reflects the demographics of the impacted population. In 2014, Pinnacle West made changes to the postretirement benefits offered to Medicare eligible retirees, which resulted in prior-service credits. We have been amortizing these prior-serviced credits since 2015 with the last full-year amortization occurring in 2024.

Contributions

We have not made any voluntary contributions to our pension plan year-to-date in 2024. 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 2024, 2025 or 2026. With regard to contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2024 and do not expect to make any contributions in 2024, 2025 or 2026.

6. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate variable interest entities ("VIEs") 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 2024 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

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

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income of $4 million for both the three months ended March 31, 2024 and 2023.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Condensed Consolidated Balance Sheets include the following amounts relating to the VIEs (dollars in thousands):

	March 31, 2024	December 31, 2023
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 85,459	$ 86,426
Equity — Noncontrolling interests	111,504	107,198

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 $334 million beginning in 2024, and up to $501 million over the lease extension 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

See Note 10 for details relating to Pinnacle West's Equity Forward Sale Agreements that are classified as equity transactions. These equity transactions are indexed to Pinnacle West common stock and qualify for a derivative scope exception. These equity transactions are not subject to mark-to-market accounting and are excluded from the derivative disclosures below.

Energy Derivatives

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on energy 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**	**March 31, 2024**	**December 31, 2023**
Power	GWh	2,097	1,212
Gas	Billion cubic feet	235	200

Gains and Losses from Energy Derivative Instruments

For the three months ended March 31, 2024 and 2023, 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 March 31,	
Commodity Contracts	**Financial Statement Location**	**2024**	**2023**
Net Loss Recognized in Income	Fuel and purchased power (a)	$(55,942)	$(188,930)

(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-

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

The following tables provide information about the fair value of APS's 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 March 31, 2024: (dollars in thousands)	**Gross Recognized Derivatives (a)**	**Amounts Offset (b)**	**Net Recognized Derivatives**	**Other (c)**	**Amounts Reported on Balance Sheets**
Current assets	$ 73	$ —	$ 73	$ 5	$ 78
Investments and other assets	—	—	—	—	—
Total assets	73	—	73	5	78
Current liabilities	(119,859)	13,100	(106,759)	(6,771)	(113,530)
Deferred credits and other	(34,872)	—	(34,872)	—	(34,872)
Total liabilities	(154,731)	13,100	(141,631)	(6,771)	(148,402)
Total	$ (154,658)	$ 13,100	$ (141,558)	$ (6,766)	$ (148,324)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $13,100 thousand 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 $6,771 thousand and cash margin provided to counterparties of $5 thousand.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2023: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 8,497	$ (1,694)	$ 6,803	$ 5	$ 6,808
Investments and other assets	—	—	—	—	—
Total assets	8,497	(1,694)	6,803	5	6,808
Current liabilities	(85,736)	10,894	(74,842)	(6,071)	(80,913)
Deferred credits and other	(42,975)	—	(42,975)	—	(42,975)
Total liabilities	(128,711)	10,894	(117,817)	(6,071)	(123,888)
Total	$ (120,214)	$ 9,200	$ (111,014)	$ (6,066)	$ (117,080)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $9,200 thousand 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 $6,071 thousand and cash margin provided to counterparties of $5 thousand.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by energy derivative counterparties and have risk management contracts with many energy derivative counterparties. As of March 31, 2024, we have no counterparties with positive exposures of greater than 10% of Pinnacle West’s risk management assets. 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 counterparties 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 energy 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).

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The following table provides information about our energy derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	March 31, 2024
Aggregate fair value of derivative instruments in a net liability position	$ 154,731
Cash collateral posted	13,100
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	127,607

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

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $206 million if our debt credit ratings were to fall below investment grade.

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 U.S. Department of Energy ("DOE") in the U.S. 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 October 31, 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 $18.46 million (APS's share is $5.4 million). On March 21, 2024, the DOE approved a payment in the amount of $18.39 million (APS's share is $5.4 million), and payment is anticipated in the second quarter of 2024.

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 January 1, 2024. As of that

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date, in accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $16.3 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $500 million, which is provided by American Nuclear Insurers. The remaining balance of approximately $15.8 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 $23.1 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 $64.1 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.

Fuel and Purchased Power Commitments and Purchase Obligations

As of March 31, 2024, our fuel and purchased power and purchase obligation commitments have increased by $295 million from the information provided in our 2023 Form 10-K. The change is primarily due to new purchased power commitments. The majority of the changes relate to 2026 and thereafter.

At March 31, 2024, we have various lease arrangements that have been executed but have not yet commenced. These arrangements primarily relate to energy storage assets, with expected lease commencement dates ranging from June 2024 through June 2025, with terms expiring through May 2045. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $7.1 billion over the term of the arrangements. The lease commencement dates for these leased assets have experienced delays. APS continues to work with the lessors to determine the revised commencement dates that will be achieved. For additional information regarding our lease commitments, see our 2023 Form 10-K.

Other than the items described above, there have been no material changes, as of March 31, 2024, outside the normal course of business in contractual obligations from the information provided in our 2023 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.

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.

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 the Arizona Department of Environmental Quality (“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 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 our financial condition, results of operations, or cash flows.

On April 25, 2024, EPA took final action on a proposal to expand the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. This new class of CCR management units ("CCRMUs"), which contain at least 1,000 tons of CCR, 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

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of CCR beneficial use (with exceptions for historical roadbed and embankment applications). Existing CCR regulatory requirements for groundwater monitoring, corrective action, closure, post-closure care, and other requirements will be imposed on such CCRMUs. At this time, APS is still evaluating the impacts of this final regulation on its business, with initial CCRMU site surveys due to be completed within 21 months following publication of this final regulation in the Federal Register. Depending on the outcome of that evaluation, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. 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. APS's estimates for its share of corrective action and monitoring costs at Four Corners and Cholla are captured within the Asset Retirement Obligations. 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 condition, 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 final regulations governing power plant carbon dioxide emissions, released April 25, 2024, EPA issued 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, these new federal regulations are limited to measures that can be installed at individual power plants to limit planet-warming carbon-dioxide 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") by 2032. For intermediate or low-load natural gas fired combustion turbines, those with 40% or less capacity factors, EPA's regulations would not require add-on pollution controls. Instead, natural gas-fired combustion turbines with capacity factors of up to 20% would be effectively unregulated, while such turbines with capacity factors over 20% and up to 40% would be subject to

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carbon dioxide emission rate limitations. EPA did not finalize standards for existing natural gas-fired combustion turbines but has indicated that it will propose a new set of standards, initiating a separate rulemaking, for these existing gas-fired power plants within the next year.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has finalized subcategories based on planned retirement dates. This means that facilities retiring before 2032 are effectively exempt from regulation, those that retire between 2032 and 2038 must co-fire with natural gas starting in 2030, and those that retire in 2039 or later must install CCS controls by 2032.

At this time, APS continues to assess the recently finalized EPA carbon emission standards and cannot yet predict their potential impact on APS's operations. The costs associated with APS's operation of its current thermal plants and construction and operation of future facilities could materially increase, which could affect our financial condition, results of operations, or cash flows.

Effluent Limitation Guidelines. EPA published effluent limitation guidelines ("ELG") on October 13, 2020, and, based off those guidelines, APS completed a National Pollutant Discharge Elimination System ("NPDES") permit modification for Four Corners on December 1, 2023. The ELG standards finalized in October of 2020 relaxed the "zero discharge" standard for bottom ash transport waters EPA finalized in September of 2015. However, on April 25, 2024, EPA finalized new ELG regulations that once again require "zero discharge" standards for flows of bottom ash transport water at power plants like Four Corners. Nonetheless, for power plants that permanently cease operations by December 31, 2034, such facilities can continue to comply with the 2020 ELG standards. APS is currently evaluating its compliance options for Four Corners based on the ELG regulations finalized in April 2024 and is assessing what impacts the new standards will have on our financial condition, results of operations, or cash flows.

EPA Good Neighbor Proposal for Arizona. On March 15, 2023, EPA issued its final Good Neighbor Plan for 23 states in order to ensure that the cross-state transport of ozone forming emissions does not interfere with downwind state compliance with the National Ambient Air Quality Standards ("NAAQS"). Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for nitrogen oxide ("NOx") emissions. While Arizona was not among the 23 states subject to EPA's March 2023 final action, EPA announced on January 23, 2024 that it was proposing to add Arizona and New Mexico (along with two other additional states) to EPA's NOx emission allowance trading program finalized last year. Since APS operates thermal power plants within Arizona and those portions of the Navajo Nation within New Mexico, APS's power plants would be subject to EPA's Good Neighbor

Plan upon finalization of this proposal. APS cannot predict the outcome of EPA’s proposal or the extent to which such regulations, if finalized, could materially impact our financial condition, results of operations, or cash flows.

Revised Mercury and Air Toxics Standard (“MATS”) Proposal. On April 25, 2024, EPA finalized revisions to the existing MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The final regulations increase the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and require the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing). These final regulations will take effect for existing coal-fired power plants, such as Four Corners, within three years of publication in the Federal Register. APS continues to evaluate this new regulation and its impact on Four Corners. Depending on the outcome of that assessment, the costs associated with APS’s controls for filterable particulate matter 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

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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 APS does not expect the outcome to have a material impact on our financial condition, results of operations, or cash flows.

BCE Kūpono Solar

BCE and Ameresco jointly owned 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. 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 closed on January 12, 2024. As a result of the BCE Sale, on March 31, 2024, Pinnacle West holds no equity or ownership interest in the Kūpono Solar Project. Subsequent to the BCE Sale, Pinnacle West continues to maintain the performance guarantees relating to the Kūpono Solar Project financing (see additional information below regarding these guarantees). See Note 14 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 March 31, 2024, standby letters of credit totaled approximately $35 million and surety bonds totaled approximately $21 million; both will expire through 2025. 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

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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 March 31, 2024. In connection with the sale of 4C Acquisition, LLC's 7% interest to Navajo Transitional Energy Corporation ("NTEC"), Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. 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 March 31, 2024, there is approximately $31 million of remaining guarantees relating to these PTC Guarantees that are expected to terminate by 2030.

Pinnacle West has issued various performance guarantees in connection with the Kūpono Solar Project investment financing and is exposed to losses relating to these guarantees upon the occurrence of certain events that we do not consider to be reasonably likely to occur. Subsequent to the BCE Sale, Pinnacle West continues to maintain these performance guarantees. See Note 14. Pinnacle West has not needed to perform under these guarantees. Maximum obligations are not explicitly stated in the guarantees and cannot be reasonably estimated. We consider the fair value of these guarantees, including expected credit losses, to be immaterial. The details of the guarantees are as follows:

- Upon the BCE Sale closing, on January 12, 2024, Pinnacle West committed to certain performance guarantees tied to the Kūpono project achieving certain construction and operation milestones. These performance guarantees will expire when the Kūpono project achieves commercial operation, which is expected in May 2024. If the Kūpono project is unable to achieve commercial operation, Pinnacle West may incur losses relating to these guarantees. The guarantees provide support relating to the $140 million Kūpono construction financing agreements, described above. As of March 31, 2024, we cannot reasonably estimate the range of loss that may occur; however, the likelihood of any payment under these guarantees is considered remote.

- When the Kūpono financing converts to a sale leaseback agreement, which is expected to occur upon commercial operation of the project, Pinnacle West has committed to certain performance guarantees that may apply upon the occurrence of specified events (such as uninsured loss events). Ameresco has agreed to make efforts to refinance the project and eliminate these guarantees prior to 2030.

- Ameresco is obligated to reimburse Pinnacle West for any payments made by Pinnacle West under such guarantees.

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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 March 31,	
	2024	2023
Other income:		
Interest income (a)	$ 7,560	$ 6,026
Gain on sale of BCE (Note 14)	22,988	—
Miscellaneous	59	51
Total other income	$ 30,607	$ 6,077
Other expense:		
Non-operating costs	$ (6,150)	$ (2,640)
Investment losses — net	(777)	(1,061)
Miscellaneous	(640)	(430)
Total other expense	$ (7,567)	$ (4,131)

(a) The 2023 and 2024 Interest income is primarily related to PSA Interest. See Note 4.

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

	Three Months Ended March 31,	
	2024	2023
Other income:		
Interest income (a)	$ 6,796	$ 5,024
Miscellaneous	59	51
Total other income	$ 6,855	$ 5,075
Other expense:		
Non-operating costs	$ (2,255)	$ (2,188)
Miscellaneous	(639)	(429)
Total other expense	$ (2,894)	$ (2,617)

(a) The 2023 and 2024 Interest income is primarily related to PSA Interest. See Note 4.

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10. Earnings Per Share and Equity Forward Sale Agreements

On February 28, 2024, Pinnacle West executed the Equity Forward Sale Agreements, which allow Pinnacle West to issue a fixed number of Pinnacle West common shares to be settled in the future. The Equity Forward Sale Agreements relate to an aggregate of 11,240,601 shares of Pinnacle West common stock that may be settled at our discretion no later than September 4, 2025. The forward sale price was initially $64.51 per share and is subject to certain adjustments in accordance with the terms of the Equity Forward Sale Agreements through the date of settlements. On a settlement date, Pinnacle West will issue shares of common stock and receive cash at the then-applicable forward sale price.

As of March 31, 2024, the Equity Forward Sale Agreements have not been settled. At March 31, 2024, Pinnacle West could have settled the Equity Forward Sale Agreements with the issuance of 11,240,601 shares of common stock in exchange for cash of $728 million. We will not receive any proceeds from the Equity Forward Sale Agreements until the settlement with shares occurs, and upon settlement, we will record the proceeds, if any, in equity. The terms of the Equity Forward Sale Agreements also allow Pinnacle West, at our option, to settle the Equity Forward Sale Agreements with the counterparties by delivering cash, in lieu of shares.

We have classified the Equity Forward Sale Agreements as an equity transaction. As a result, no amounts have been recorded on the Condensed Consolidated Balance Sheets relating to the Equity Forward Sale Agreements as of March 31, 2024. Delivery of shares to settle the Equity Forward Sale Agreements will eventually result in dilution to basic earnings per share ("EPS") upon settlement. Prior to settlement, the potentially issuable shares are reflected in our diluted EPS calculations using the treasury stock method. Under this method, the number of shares of Pinnacle West common stock used in calculating diluted EPS for a reporting period is increased by the number of shares, if any, that would be issued upon settlement less that number of shares that could be purchased by Pinnacle West in the market with the proceeds received from issuance (based on the average market price during that reporting period). Share dilution occurs when the average market price of our stock during the reporting period is higher than the adjusted forward sale price as of the end of the reporting period.

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

	Three Months Ended March 31,	
	2024	2023
Net income (loss) attributable to common shareholders	$ 16,862	$ (3,297)
Weighted average common shares outstanding — basic	113,621	113,358
Net effect of dilutive securities:		
Contingently issuable performance shares and restricted stock units	327	239
Dilutive shares related to equity forward sale agreements	279	—
Total contingently issuable shares	606	239
Weighted average common shares outstanding — diluted	114,227	113,597
Earnings per weighted-average common share outstanding:		
Net income (loss) attributable to common shareholders — basic	$ 0.15	$ (0.03)
Net income (loss) attributable to common shareholders — diluted	$ 0.15	$ (0.03)

For the three months ended March 31, 2023, 239,000 shares were excluded from the calculation of diluted weighted average common shares outstanding, as their inclusion would have been antidilutive. The net income attributable to common shareholders was calculated using the weighted average number of common shares outstanding of 113,537,689. For the three months ended March 31, 2024, no shares were excluded from the calculation of diluted weighted average common shares outstanding.

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

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the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of Net Asset Value (“NAV”) as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, 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 2023 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. Long-dated energy transactions may 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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

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 March 31, 2024, 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	—	—	73	5	(a)	78
Nuclear decommissioning trust:						
Equity securities	9,590	—	—	2,129	(b)	11,719
U.S. commingled equity funds	—	—	—	384,687	(c)	384,687
U.S. Treasury debt	343,985	—	—	—		343,985
Corporate debt	—	218,595	—	—		218,595
Mortgage-backed securities	—	214,514	—	—		214,514
Municipal bonds	—	52,053	—	—		52,053
Other fixed income	—	13,471	—	—		13,471
Subtotal nuclear decommissioning trust	353,575	498,633	—	386,816		1,239,024
Other special use funds:						
Equity securities	46,665	—	—	1,423	(b)	48,088
U.S. Treasury debt	316,137	—	—	—		316,137
Subtotal other special use funds	362,802	—	—	1,423		364,225
Total assets	$ 716,392	$ 498,633	$ 73	$388,244		$1,603,342
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(138,687)	$ (16,044)	$ 6,329	(a)	$ (148,402)

(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, 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	$ 10	$ —	$ —	$ —		$ 10
Risk management activities — derivative instruments:						
Commodity contracts	—	1,881	6,616	(1,689)	(a)	6,808
Nuclear decommissioning trust:						
Equity securities	11,064	—	—	(767)	(b)	10,297
U.S. commingled equity funds	—	—	—	409,616	(c)	409,616
U.S. Treasury debt	319,734	—	—	—		319,734
Corporate debt	—	188,317	—	—		188,317
Mortgage-backed securities	—	208,306	—	—		208,306
Municipal bonds	—	59,323	—	—		59,323
Other fixed income	—	5,653	—	—		5,653
Subtotal nuclear decommissioning trust	330,798	461,599	—	408,849		1,201,246
Other special use funds:						
Equity securities	40,991	—	—	2,196	(b)	43,187
U.S. Treasury debt	319,594	—	—	—		319,594
Subtotal other special use funds	360,585	—	—	2,196		362,781
Total assets	$ 691,393	$ 463,480	$ 6,616	$ 409,356		$1,570,845
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(127,016)	$ (1,695)	$ 4,823	(a)	$ (123,888)

(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.

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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31, 2024, and December 31, 2023:

	March 31, 2024 Fair Value (thousands)		Valuation	Significant		Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**	**Technique**	**Unobservable Input**	**Range**	**(c)**
Electricity:						
Forward Contracts (a)	$ 73	$ 13,206	Discounted cash flows	Electricity forward price (per MWh)	$25.27 - $247.22	$ 135.29
Option Contracts (b)	—	801	Option model	Electricity forward price (per MWh)	$42.75 - $103.25	$ 66.67
				Electricity price volatilities	154 % - 285 %	203 %
				Natural gas forward price (per MMBtu)	$2.08 - $4.83	$ 3.11
				Natural gas price volatilities	56 % - 78 %	69 %
Natural Gas:						
Forward Contracts (a)	—	2,037	Discounted cash flows	Natural gas forward price (per MMBtu)	$ (0.14) - $0.02	$ (0.01)
Total	$ 73	$ 16,044				

(a) Includes swaps and physical and financial contracts.

(b) Option contracts classified as Level 3 relate to purchase power heat rate options. Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

(c) Unobservable inputs were weighted by the relative fair value of the instrument.

	December 31, 2023 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weig Aver (**
Electricity:						
Forward Contracts (a)	$6,587	$ 658	Discounted cash flows	Electricity forward price (per MWh)	$37.79 - $259.04	$ 15
Natural Gas:						
Forward Contracts (a)	29	1,037	Discounted cash flows	Natural gas forward price (per MMBtu)	$0.00 - $0.08	$
Total	$6,616	$ 1,695				

(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 March 31,	
Commodity Contracts	**2024**	**2023**
Net derivative balance at beginning of period	$ 4,921	$ (4,888)
Total net losses realized/unrealized:		
Deferred as a regulatory asset or liability	(23,600)	(30,427)
Settlements	2,708	41,937
Net derivative balance at end of period	$ (15,971)	$ 6,622

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.

Non-recurring Financial Instruments Measured at Fair Value

As of March 31, 2024, the fair value of certain Pinnacle West guarantees issued relating to BCE that have been measured at fair value on a nonrecurring basis was $2 million, which was valued using unobservable inputs (Level 3). See Notes 8 and 14.

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 2023, APS was reimbursed $14 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 assets. 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):

	March 31, 2024					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 394,277	$ 46,665	$ 440,942		$ 325,101	$ —
Available for sale-fixed income securities	842,618	316,137	1,158,755	(a)	12,056	(48,075)
Other	2,129	1,423	3,552	(b)	164	—
Total	$ 1,239,024	$ 364,225	$1,603,249		$ 337,321	$ (48,075)

(a) As of March 31, 2024, the amortized cost basis of these available-for-sale investments is $1,194,000 thousand.
(b) Represents net pending securities sales and purchases.

	December 31, 2023					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 420,680	$ 40,991	$ 461,671		$ 336,555	$ —
Available for sale-fixed income securities	781,333	319,594	1,100,927	(a)	21,518	(40,868)
Other	(767)	2,196	1,429	(b)	39	—
Total	$ 1,201,246	$ 362,781	$1,564,027		$ 358,112	$ (40,868)

(a) As of December 31, 2023, the amortized cost basis of these available-for-sale investments is $1,120,000 thousand.
(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 March 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2024			
Realized gains	$ 54,492	$ 80	$ 54,572
Realized losses	$ (2,815)	$ —	$ (2,815)
Proceeds from the sale of securities (a)	$ 377,822	$ 66,048	$ 443,870
2023			
Realized gains	$ 1,210	$ —	$ 1,210
Realized losses	$ (5,694)	$ —	$ (5,694)
Proceeds from the sale of securities (a)	$ 136,185	$ 90,441	$ 226,626

(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 March 31, 2024, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 24,043	$ 59,198	$ 37,081	$ 120,322
1 year – 5 years	254,711	43,219	151,844	449,774
5 years – 10 years	193,975	—	24,795	218,770
Greater than 10 years	369,889	—	—	369,889
Total	$ 842,618	$ 102,417	$ 213,720	$ 1,158,755

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31				
Balance December 31, 2023	$ (34,754)		$ 1,610	$ (33,144)
OCI (loss) before reclassifications	—		—	—
Amounts reclassified from accumulated other comprehensive loss	562	(a)	—	562
Balance March 31, 2024	$ (34,192)		$ 1,610	$ (32,582)
Balance December 31, 2022	$ (32,332)		$ 897	$ (31,435)
OCI (loss) before reclassifications	—		(616)	(616)
Amounts reclassified from accumulated other comprehensive loss	515	(a)	—	515
Balance March 31, 2023	$ (31,817)		$ 281	$ (31,536)

(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 March 31			
Balance December 31, 2023	$	(17,219)	
OCI (loss) before reclassifications		—	
Amounts reclassified from accumulated other comprehensive loss		490	(a)
Balance March 31, 2024	$	(16,729)	
Balance December 31, 2022	$	(15,596)	
OCI (loss) before reclassifications		—	
Amounts reclassified from accumulated other comprehensive loss		457	(a)
Balance March 31, 2023	$	(15,139)	

(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

14. 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 was structured to close in multiple stages that were completed on January 12, 2024. Certain investments and assets that BCE previously held, 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 wholly-owned subsidiary of Pinnacle West. The BCE Sale did 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 BCE assets and liabilities were included in the BCE Sale and were transferred to Ameresco.

The total carrying value of net assets transferred to Ameresco as a result of the BCE Sale totaled $79 million, with total consideration received by Pinnacle West of $108 million, resulting in a total pre-tax gain of $29 million, which was recognized between August 4, 2023 and January 12, 2024. The net assets transferred includes $41 million of liabilities that have been assumed by Ameresco. The consideration received by Pinnacle West includes both cash and interest-bearing promissory notes. The stages of the BCE Sale and timing of net assets transferring to Ameresco and related gain recognition are as follows:

- The first stage of the BCE Sale was completed on August 4, 2023. In the first stage, the net assets transferred to Ameresco totaled $44 million, which included a $36 million construction term loan. See Note 3. The assets and liabilities transferred in the first 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. A gain of $6 million was recognized on our Consolidated Statements of Income for the year ended December 31, 2023, relating to the first stage of the BCE Sale.

- The final stage of the BCE Sale was completed on January 12, 2024. In the final stage, the net assets transferred to Ameresco totaled $35 million. The assets transferred in the final stage related primarily to equity method investments in the Kūpono Solar Project and other development stage projects. These assets were previously classified as assets held for sale on our December 31, 2023, Consolidated Balance Sheets. Our Condensed Consolidated Statements of Income for the three months ended March 31, 2024, include a $23 million gain relating to the final stage of the BCE Sale.

As of January 12, 2024, all stages of the BCE Sale have been completed. As partial consideration for the BCE Sale, Pinnacle West received $46 million of interest-bearing promissory notes from Ameresco. The notes require Ameresco to make cash payments to Pinnacle West throughout 2024. We expect to receive full payment, and interest, on the notes no later than August 4, 2024. Our March 31, 2024 Condensed Consolidated Balance Sheets include $46 million of notes receivable and a $2 million estimated credit reserve.

On January 30, 2024, Pinnacle West entered into a tax credit transfer agreement to purchase from Ameresco $23.3 million of investment tax credits from the BCE Los Alamitos project for $21 million. See Note 15.

Additionally, Pinnacle West continues to maintain certain guarantees relating to the Kūpono Solar Project financing, which were not transferred in the BCE Sale transaction. See Note 8.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

15. Income Taxes

On January 30, 2024, Pinnacle West entered into a tax credit transfer agreement to purchase from Ameresco $23.3 million of investment tax credits from the BCE Los Alamitos project for $21 million. See Note 14 for more information about the BCE Sale.

As a part of the Inflation Reduction Act of 2022 ("IRA"), a new PTC for nuclear energy produced by existing nuclear energy plants was enacted, available from 2024 through 2032. The Nuclear PTC can be increased by five times if certain IRS prevailing wages rules are met. The Company continues to await guidance from the U.S. Treasury Department related to the definition of "gross receipts" from nuclear sales for purposes of the credit phase-out applicable to the nuclear PTC. Without such guidance, the Company is unable to make a reasonable estimate of the potential benefit the nuclear PTC may provide. As a result, no income tax benefits have been recorded related to the nuclear PTC as of March 31, 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 2023 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 approximately $25 billion. Since 1884, 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 Generating Station ("Palo Verde") — a primary source of electricity for the southwestern United States.

Inflation Reduction Act of 2022

The Inflation Reduction Act of 2022 ("IRA") significantly expands the availability of tax credits for investments in clean energy generation technologies and energy storage. Key provisions that are relevant to APS'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 Department have issued preliminary guidance related to various provisions of the IRA that have enabled APS to claim credits related to its 2023 solar and battery investments. The Company continues to await regulations and other guidance, including with respect to the nuclear PTC, which will provide additional details and clarifications regarding how the Company may be able to claim IRA tax credits in future years. See Note 15 for more information.

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.

Strategic Overview

Our strategy is to create a sustainable energy future for Arizona that delivers shareholder value and shared value by serving our customers with reliable, affordable, and clean energy.

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. This multi-year objective includes incrementally improving APS's J.D. Power ("JDP") overall customer satisfaction ratings to achieve a 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, 2022, and 2023. At the end of 2023, APS's residential customer satisfaction ranked in the second quartile among large investor-owned utilities, and its business customer satisfaction ranked in the second quartile of utilities nationally.

Through APS's efforts to further drive a customer-centric culture in 2023 and beyond, employees delivered an enhanced customer experience through a number of ongoing initiatives, including improving the ease-of-use of APS's automated phone system and advancing phone advisor soft skill development through updated training curriculum, and adding 1,100-plus in-person payment locations, as well as introducing new customer payment channels. APS also implemented numerous enhancements to its website, including improving page-loading speeds, adding user-friendly dashboards, and making content more simple, relevant, and useful. APS enhanced other customer touchpoints, such as communications throughout outages and the online outage center in addition to continuing to communicate with customers in their preferred channels about topics that matter most to them, such as reliability, energy-efficiency, financial assistance, the environment, and programs that enable them to design their own personalized energy experience. To further improve customer communications, APS expanded the use of email and text alerts, notifications, and communications to customers related to outages and their account and service status. Finally, APS continues to focus on employee learning, training, tools, and resources to ensure all employees understand their role in APS customers' experiences.

Additionally, APS has implemented a variety of financial assistance programs to assist customers struggling to pay their energy bills. Among these assistance programs are discounts for qualified limited-income customers, and other non-income-based assistance programs, including flexible payment arrangements and emergency utility bill assistance. To ensure our most vulnerable customers are connected to these programs, we train and partner with more than one hundred community action agencies across our service territory.

Reliable

While our energy mix evolves, APS’s 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 those experienced in other industries.

Planned investments will support operating and maintaining the grid, updating technology, accommodating customer growth, and enabling more renewable energy resources. To prioritize reliability and meet substantial growth in residential and commercial energy needs, APS has developed a future-focused, strategic transmission plan. This Ten-Year Plan includes five critical transmission projects that comprise the APS strategic transmission portfolio, which represents a significant upgrade to APS’s transmission system. These five projects, along with other projects included in the Ten-Year Plan, are intended to support growing energy needs, strengthen reliability, and allow for the connection of new resources.

Our advanced distribution management system allows operators to locate outages and 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. We also increased spend on mitigating the risk associated with trees that could cause hazards, resulting in more of these trees being removed before they could cause outages or wildfires. 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 devoting 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. APS completed implementation of best-in-class fire modelling software that we are utilizing to more surgically identify and calculate risk and target future system improvement investments such as fire-resistant pole wrapping, wood to steel pole conversions, and additional remote-controllable field devices like reclosers and switches. APS also has implemented a public safety power shutoff (“PSPS”) program for this upcoming fire season, leveraging the additional real-time analysis provided by the new modelling software, and has begun education outreach to customers and communities that may potentially be impacted by the PSPS program. We continue to evaluate policy and regulatory options, as well as insurance programs, to mitigate the impact of wildfire events.

Maintaining reliability and affordability for our customers during the clean energy transition is fundamental to our strategy. As a critical partner to the large quantity of renewables and energy storage we are adding to our system, natural gas generation will play an important role in maintaining reliability for our customers. One example is the 2019 addition of new natural gas units at the modernized Ocotillo Power Plant to provide cleaner-running and more efficient units. Additionally, efficiency improvements to gas units at the Redhawk and Sundance Power Plants are planned in 2024.

As part of a balanced energy portfolio, these flexible resource additions 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. Complementary to and in support of the transition to renewable resources, APS continues to evaluate and pursue options to meet growing energy demand and ensure grid reliability, including through upgrades, expansions, and/or modernization of existing natural gas facilities.

In October 2021, APS announced plans to evaluate regional market solutions as part of the Western Markets Exploratory Group (“WMEG”). As a member of WMEG, APS explored 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 regulations and known and expected market design. APS utilizes the work done by WMEG to help identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers.

APS went live with a new Energy Management System (“EMS”) in April 2024. APS expects the new EMS to provide a better foundation which will improve future integration of the renewable and energy storage assets into APS’s generation resource portfolio, allowing APS to maximize the flexibility of its resources and fully engage in the Energy Imbalance Market. APS also believes it will also better position APS to participate in market opportunities that develop over the next decade.

APS's key elements to delivering reliable power include resource planning, sufficient reserve margins, partnering with customers to manage peak demand, fire mitigation, and operational preparedness, among others. 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.

Affordable

APS continues to focus on mitigating the cost pressures related to the current inflationary environment. Overall inflation grew by 2.2% in Phoenix and 3.2% nationally over the twelve months ended February 2024. While inflationary impacts to APS have begun to slow in the first quarter of 2024, select categories such as chemicals have seen increases up to 55% due to regional raw material constraints. Additionally, APS has seen inflationary impacts in select equipment, particularly those that contain semiconductor components or that are labor intensive. Inflation continues to impact service rates and spend categories through pass-through costs, such as suppliers' increased material costs, cost of insurance, and wage rates.

APS's customer affordability initiative includes internal opportunities, such as training and mentoring employees on identifying efficiency opportunities; maintaining an inventory to take advantage of lower pricing and avoid expediting fees; entering into long-term contracts to hedge against price volatility, which has allowed APS to mitigate against procurement spend areas such as transformers; and implementing automation technologies to enhance efficiencies and increase data-oriented decision making.

There are also external opportunities under APS's customer affordability initiative, such as APS's participation in the Western Energy Imbalance Market ("WEIM"). WEIM 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 WEIM 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 participated in market design and tariff development of Markets+, a day-ahead and real-time market offering from Southwest Power Pool that was filed with the U.S. Federal Energy Regulatory Commission ("FERC") on March 29, 2024. APS also participated in the design and drafting of the tariff for the CAISO's Extended Day-Ahead Market, which was approved by FERC in December 2023. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool. These regional efforts are driven by three objectives of reducing customer cost, improving reliability, and incorporating more clean energy on APS's system.

In terms of generation affordability, every three years, APS performs a comprehensive study, called an Integrated Resource Plan ("IRP"), to identify what resources will be necessary to safely and reliably meet the demand and energy needs of its customers over the next 15 years. In November 2023, APS released its latest IRP, which identified forecasted customer demand and energy needs growing at an unprecedented rate. In developing the IRP, APS considered how factors such as forecasted economic growth, new resource technology availability, and weather impact the amount and type of resources required to reliably meet customer needs. These inputs are then used to develop a plan that identifies a balanced mix of energy generating resources that reliably serves customers' future energy needs in the most affordable and sustainable manner possible. Ensuring that the most affordable and reliable resources are selected to meet future customer needs, APS issued competitive solicitations through all-source request for proposals ("RFPs") in 2022 and 2023. These RFPs were open to all resource types, including customer-scale (behind the meter) and utility-scale (front of the meter) resources. Through this process, APS has consistently found that clean resources like wind, solar, and energy storage technology, are important elements of a least cost portfolio. Over the long term, these resources are expected to provide value as part of a diverse energy mix.

In addition to managing the cost of electricity generation, APS has continued building upon existing cost management efforts, including a customer affordability initiative launched in 2019. The initiative was implemented Company-wide to thoughtfully and deliberately assess our areas ranging from 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, mitigate cost increases, increase employee retention, and improve customer satisfaction.

Clean Energy Commitment

We are committed to doing our part to build a clean and carbon-free future. 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 by providing reliable, affordable, and clean energy to our customers. We can accomplish our vision by collaborating with customers, communities, employees, policymakers, shareholders, and other stakeholders. Our clean energy commitment 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 commitment consists of three parts:

- A 2050 goal to provide 100% clean, carbon-free electricity;
- A 2030 target to achieve 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 depends upon a number of important external factors, including a supportive regulatory environment, sales and customer growth, development of clean energy technologies, and continued access to capital markets among others.

2050 Goal: 100% Clean, Carbon-Free Electricity. Achieving a fully clean, carbon-free energy mix by 2050 is our aspiration. Achieving this 2050 goal will require, among other things, innovative thinking, emergent clean energy and storage technologies, upgrades and expansions to the grid, and supportive public policy.

2030 Goal: 65% Clean Energy. APS has an energy mix that is already 50% clean and plans to continue to add more renewables and energy storage. 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 resources such as solar, wind, and biomass, and is measured in accordance with the Arizona Corporation Commission's (the "ACC")

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 the Four Corners Power Plant ("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 annual carbon emissions that were 36% lower in 2023 compared to 2005. In addition, APS has committed to end the use of coal at its remaining Cholla Power Plant units during 2025.

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. As of the date of this report, APS has elected not to begin seasonal operation due to market conditions.

Renewables. APS's IRP establishes the path to maintaining reliability for our expanding customer base through investments in a broad subset of technologies. Our IRP shows that renewable and clean resources are an important part of a reliable, least cost portfolio. APS continues to issue frequent RFPs to procure resources. See Note 4.

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, one of 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 power purchase agreements ("PPAs") that will enable investments with greater financial flexibility.

APS uses competitive 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.

On June 30, 2023, APS issued an 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 has started negotiations on multiple projects, including a 400 MW wind facility PPA that was signed in December 2023, which was later amended to 500 MW in January 2024.

The following table summarizes the resources in APS's renewable energy portfolio that are in operation or under development as of March 31, 2024. 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	716
Geothermal	10	—
Biomass	14	—
Biogas	3	—
Total Purchased Power Agreements	1,034	1,977
Total Distributed Energy: Solar (a)	1,657	64 (b)
Total Renewable Portfolio	3,106	2,041

(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.

As noted above, on June 30, 2023, APS issued the 2023 RFP seeking approximately 1,000 MW of reliable capacity, including at least 700 MW of renewable resources, including energy storage, with a focus on in-service dates between 2026 and 2028.

APS currently plans to install more than 2,700 MW of utility scale energy storage by 2026, including through energy storage projects under PPAs and AZ Sun Program retrofits as well as through 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 March 31, 2024. 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	201	(a)	—
Purchase Power Agreements - Energy Storage	60		2,182
Customer-Sited Energy Storage	33		20
Total Energy Storage Portfolio	**294**		**2,202**

(a) Includes 0.3 MW of APS-owned customer-sited.

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 southwestern 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.

Developing Clean Energy Technologies

Electric Vehicles

As a part of the statewide transportation electrification plan ("TE Plan") adopted in 2021, the ACC approved a target of 450,000 light-duty electric vehicles ("EVs") in its service territory by 2030. APS's Take Charge AZ ("TCAZ") program has helped to deploy Level 2 EV charging stations on customer properties for fleet, public, and workplace EV charging. As of March 31, 2024, APS energized 784 Level 2 charging ports at 188 customer locations. Additionally, APS has energized direct current fast charging ("DCFC") stations that are owned and operated by APS at five locations in Arizona: Sedona, Prescott, Globe, Show Low, and Payson. Effective December 12, 2023, the TCAZ program was discontinued by the ACC. As part of that decision, APS was permitted to complete certain projects that were in process as of December 12, 2023.

Additionally, as part of APS's DSM Implementation Plan, APS launched the EV Charging Demand Management Pilot to proactively address the growing electric demand from charging as EVs become more widely adopted. The EV programs in the DSM Implementation Plan include APS SmartCharge (an EV data gathering program), Fleet Advisory Services, and a $100 rebate to home builders for new homes to be built EV-ready with 240V receptacle. APS previously offered a $250 residential rebate to customers that purchased a qualifying home Level 2 charger. Effective December 12, 2023, APS discontinued this rebate per the ACC decision. See the discussion above.

APS filed its 2024 DSM Implementation Plan on November 30, 2023. The 2024 DSM Implementation Plan includes APS's 2024 TE Plan and, among other things, proposes two new programs: an expanded residential EV Managed Charging program and a Commercial EV Make-Ready Program. On April 26, 2024, APS filed an amended 2024 DSM Implementation Plan. The amended 2024 DSM Implementation Plan includes an updated budget to reflect removal of all incentive funds for the EV Charging Demand Management Pilot, an update on the performance incentive calculation, and the withdrawal of tranches two and three of the residential battery pilot. The amended 2024 DSM Plan is still pending ACC review and approval. APS cannot predict the outcome of this proceeding. See Note 4.

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 the U.S. Environmental Protection Agency's ("EPA") proposed Greenhouse Gas ("GHG") rule. On May 23, 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 dependent upon a variety of factors including retirement date and operating capacity. See Note 8 for more information.

Sustainability Practices

In 2020, in support of our clean energy commitment and the growing focus on sustainability within our organization, we increased our focus on sustainability by dedicating a new Sustainability Department at Pinnacle West responsible for integrating responsible business 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 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 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 benchmarked best practices within the top four PSIs and has utilized this information to identify opportunities for improvement.

Finally, the Company maintains an annual Corporate Responsibility Report on the Pinnacle West website (www.pinnaclewest.com/corporate-responsibility). The report provides information related to the Company's sustainability practices and performance. The information on Pinnacle West's website, including the Corporate Responsibility Report, is not incorporated by reference into or otherwise a part of this report.

Artificial Intelligence

To address the emergence of artificial intelligence technology risk and opportunities, APS has developed a cross functional governance structure with leadership and experts from our information technology, cybersecurity, human resources, ethics, supply chain, legal, and nuclear generation teams. This cross functional structure will assess both the opportunities and risks during the technology intake process to ensure compliance with data security and reliability requirements, while observing market trends in this rapidly evolving area.

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 would have represented 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 would have been an increase of 13.6%.

The principal provisions of APS's application were:

- 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 ("DSM") 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.

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 recommended 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 recommended, 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 were:

- 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 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, 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.

On November 6, 2023, and November 21, 2023, APS and stakeholders filed briefs in the 2022 Rate Case. APS's briefs included the reduction of the total revenue requirement increase to $376.2 million and a resulting average annual customer bill impact increase of 11.1%. All other major provisions from APS's rejoinder testimony were maintained in its briefs. ACC Staff's briefs included a proposed total revenue requirement increase from $281.9 million to $282.7 million and also included their support of APS's SRB mechanism, contingent on increased stakeholder outreach.

On January 25, 2024, an Administrative Law Judge issued a Recommended Opinion and Order in the 2022 Rate Case, as corrected on February 6, 2024 (the "2022 Rate Case ROO"). The 2022 Rate Case ROO recommended, among other things, (i) a $523.1 million increase in the annual base rate revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.36%, (v) 12 months of post-test year plant and the inclusion of the Four Corners ELG project, (vi) the approval of APS's SRB proposal with certain procedural and other modifications, (vii) no additional CCT funding, (viii) a 5.0% return on the prepaid pension asset and a return of 5.35% on the OPEB liability, and (ix) no disallowances on APS's coal contracts.

The 2022 Rate Case ROO also recommended a number of changes to existing adjustors, including (i) the approval of modified DSM performance incentives and the requested DSM transfer to base rates, (ii) the retention of $1.9 million of REAC in the adjustor rather than base rates, (iii) a partial transfer of $27.1 million of LFCR funds to base rates, and (iv) the adoption of an increase in the annual PSA cap to $0.006/kWh.

On February 22, 2024, the ACC approved a number of amendments to the 2022 Rate Case ROO that resulted in, among other things, (i) an approximately $491.7 million increase in the annual base revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.39%, (v) a return set at the Company’s weighted average cost of capital on the net prepaid pension asset and net other post-employment benefit liability in rate base, (vi) an adjustment to generation maintenance and outage expense to reflect a more reasonable level of test year costs, (vii) approval of the SRB mechanism with modifications to customer notifications, procedural timelines and the inclusion of any qualifying technology and fuel source bid received through an RFP, and (viii) recovery of all DSM costs through the DSMAC rather than through base rates.

The ACC’s decision results in an expected total net annual revenue increase for APS of approximately $253.4 million and a roughly 8% increase to the typical residential customer’s bill. The ACC issued the final order for the 2022 Rate Case on March 5, 2024, with the new rates becoming effective for all service rendered on or after March 8, 2024.

Six intervenors and the Attorney General of Arizona requested rehearing on various issues included in the ACC’s decision, such as the grid access charge (“GAC”) for solar customers, the SRB, and CCT funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, Arizona Solar Energy Industries Association, Solar Energy Industries Association, and Vote Solar for the limited purpose of reviewing arguments concerning the GAC. Specifically, rehearing is ordered as to whether the GAC rate is just and reasonable, including whether it should be higher or lower, whether the GAC rate constitutes a discriminatory fee to solar customers, and whether omission of a GAC charge is discriminatory to non-solar customers. All other applications for rehearing were denied. The parties seeking rehearing have 30 days after the denial or granting of a request for rehearing to file a notice of appeal to the Arizona Court of Appeals. A procedural conference was held on April 26, 2024 for the purpose of discussing the procedural schedule for the matter. APS cannot predict the outcome of any subsequent proceedings.

2019 Retail Rate Case

On October 31, 2019, APS filed an application with the ACC (the “2019 Rate Case”) for an annual increase in retail base rates. 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. Subsequently, the ACC approved an amended 2019 Rate Case ROO on November 2, 2021. See Note 4 for information regarding the 2019 Rate Case ROO.

After the 2019 Rate Case decision, APS filed an application for rehearing of the 2019 Rate Case and later filed a Notice of Direct Appeal by APS at the Arizona Court of Appeals, requesting review of certain matters from the 2019 Rate Case decision. The Arizona Court of Appeals affirmed in part and reversed in part the ACC’s decision in the 2019 Rate Case, remanding the issue to the ACC for further proceedings. On June 14, 2023, APS and the ACC Legal Division filed a joint resolution with the ACC to allow recovery of $215.5 million in costs related to the installation of the Four Corners selective catalytic reduction (“SCR”) project, 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. As of March 31, 2024, $12.7 million of the $59.6 million of lost revenue has been recovered. Finally, the CRS tariff has been updated to account for changes to return on equity and depreciation and deferral adjustments approved in Decision No. 79293 in the 2022 Rate Case. See Note 4 for more information regarding the 2019 Rate Case and Four Corners SCR cost recovery.

Regulatory Lag Docket

On January 5, 2023, the ACC opened a new docket to explore the possibility of modifications to the ACC's historical test year rules. The ACC requested comments from utilities and interested parties on ways to reduce regulatory lag, including alternative ratemaking structures such as future test years and hybrid test years. APS filed comments on June 1, 2023. On March 19, 2024, the ACC held a workshop to discuss modifying the state's rate case test year rules. Utilities, including APS, spoke about alternatives to the current rules that could reduce regulatory lag. The ACC plans to hold another workshop on this topic and has invited further comments from stakeholders. On April 19, 2024, a letter was filed to the docket by an ACC commissioner discussing the potential benefits of modifying test year rules, including the potentiality of offering utilities to choose the type of test year that best suits them. The letter also recommended that this issue be discussed at the next possible open meeting. APS cannot predict the outcome of this matter.

See Note 4 for information regarding additional regulatory matters.

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

Pinnacle West Power, LLC ("PNW Power"). 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 "BCE Sale"). The transaction was accounted for as the sale of a business and closed in multiple stages. Certain investments and assets that BCE previously held, 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 wholly-owned subsidiary of Pinnacle West.

The BCE Sale transaction was accounted for as the sale of a business and closed in multiple stages. The final closing of the BCE Sale was completed on January 12, 2024. See Note 14 for additional details.

PNW Power's investments include TransCanyon, a 50/50 joint venture that was formed in 2014 with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. 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.

PNW Power's investments also include minority ownership positions in two wind farms operated 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, in the fourth quarter of 2022, PNW Power's equity method investment was fully impaired. Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. PNW Power indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado Investment Company ("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 has committed to the following:

- $25 million investment in the Energy Impact Partners fund, of which $17.2 million has been funded as of March 31, 2024. Energy Impact Partners is an organization that focuses on fostering innovation and supporting the transformation of the utility industry.

- $25 million investment in AZ-VC (formerly invisionAZ Fund), of which $8.7 million has been funded as of March 31, 2024. AZ-VC 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 Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in Arizona.

The remainder of these investment commitments will be contributed by El Dorado as each investment fund selects and makes investments.

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 2021 through 2023, retail electric revenues comprised approximately 91% 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 1.8% for the three-month period ended March 31, 2024, compared with the prior-year period. For the three years through 2023, APS’s customer growth averaged 2.1% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2024 and the average annual growth to be in the range of 1.5% to 2.5% through 2026 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 5.9% for the three-month period ended March 31, 2024, 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.

For the three years through 2023, annual retail electricity sales growth averaged 2.6%, 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 2.0% to 4.0% for 2024 and that average annual growth will be in the range of 4.0% to 6.0% through 2026, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, but excluding the effects of weather variations. These projected sales growth ranges include the impacts of several large data centers and new large manufacturing facilities, which are expected to contribute to 2024 growth in the range of 2.5% to 3.5% and to average annual growth in the range of 3.0% to 5.0% through 2026.

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 future extra-large projects of over 25 MW. Because of the high growth in demand for such projects, APS has developed a prioritization queue that identifies and prioritizes projects while maintaining system reliability and affordability for existing APS customers. APS is exploring available options for securing sufficient electric generation and transmission to meet these projections of future customer needs.

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, responses to retail price changes, changes in regulatory standards, and impacts of new and existing laws and regulations, including environmental laws and regulations. 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.

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 mostly 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 increases in intangible assets 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. See Note 5.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by changes in plant balances related to new investments and improvements to existing facilities, 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.

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions, and non-taxable items, such as allowance for funds used during construction (“AFUDC”). In addition, income taxes may also be affected by the settlement of issues with taxing authorities. See Note 15.

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 into service.

RESULTS OF OPERATIONS

Pinnacle West’s 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. All other segment activities are insignificant. Our regulated electricity segment activities are conducted primarily through our wholly-owned subsidiary, APS.

Operating Results — Three-month period ended March 31, 2024, compared with three-month period ended March 31, 2023.

Our consolidated net income attributable to common shareholders for the three months ended
March 31, 2024, was $17 million, compared with consolidated net loss attributable to common shareholders of $3 million for the prior-year period. The results reflect an increase of approximately $20 million, primarily as a result of the impacts of new retail base rates, increased customer growth and usage, higher CRS and LFCR revenue, and higher other income mainly due to the gain on the sale of BCE. See Note 14. These positive factors were partially offset by higher depreciation and amortization expense mostly due to increased plant assets, higher interest charges, net of AFUDC, the effects of weather, and higher operations and maintenance expense.

The following table presents net income attributable to common shareholders compared with the prior year for Pinnacle West consolidated and for APS consolidated:

	Pinnacle West Consolidated			APS Consolidated		
	Three Months Ended March 31,			Three Months Ended March 31,		
	2024	2023	Net Change	2024	2023	Net Change
	(dollars in millions)					
Operating revenues	$ 952	$ 945	$ 7	$ 952	$ 945	$ 7
Fuel and purchased power expense	(358)	(395)	37	(358)	(395)	37
Operating revenues less fuel and purchased power expenses	594	550	44	594	550	44
Operations and maintenance	(258)	(250)	(8)	(254)	(246)	(8)
Depreciation and amortization	(210)	(192)	(18)	(210)	(192)	(18)
Taxes other than income taxes	(59)	(57)	(2)	(59)	(57)	(2)
Pension and other postretirement non-service credits, net	12	10	2	12	10	2
Allowance for equity funds used during construction	10	15	(5)	10	15	(5)
Other income and expenses, net	23	1	22	4	2	2
Interest charges, net of allowance for borrowed funds used during construction	(87)	(75)	(12)	(74)	(64)	(10)
Income taxes	(4)	(1)	(3)	(4)	(3)	(1)
Less income related to noncontrolling interests	(4)	(4)	—	(4)	(4)	—
Net Income (Loss) Attributable to Common Shareholders	$ 17	$ (3)	$ 20	$ 15	$ 11	$ 4

Operating revenues less fuel and purchased power expenses. Operating revenues less fuel and purchased power expenses were $44 million higher for the three months ended March 31, 2024, 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)		
Impact of new retail base rates from 2022 Rate Case, effective March 8, 2024 (Note 4)	$ 17	$ —	$ 17
Higher retail revenue due to changes in usage patterns and customer growth partially offset by the impacts of energy efficiency and related pricing	29	12	17
CRS revenue (Note 4)	11	—	11
LFCR revenue (Note 4)	8	—	8
Lower transmission revenues (Note 4)	(5)	—	(5)
Effects of weather	(13)	(3)	(10)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(44)	(46)	2
Miscellaneous items, net	4	—	4
Total	$ 7	$ (37)	$ 44

Operations and maintenance. Operations and maintenance expenses increased $8 million for the three months ended March 31, 2024, compared with the prior-year period primarily due to:

- An increase of $2 million related to information technology costs;
- An increase of $2 million related to nuclear generation costs;
- An increase of $2 million related to transmission, distribution, and customer service costs; and
- An increase of $2 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $18 million higher for the three months ended March 31, 2024, compared to the prior-year period primarily due to increased plant in service and increased intangible assets.

Other income and expenses, net. Other income and expenses, net were $22 million higher for the three months ended March 31, 2024, compared to the prior-year period, primarily due to the gain on the sale of BCE (see Note 14), and higher interest income. The difference between APS's and Pinnacle West's other income and expense, net is primarily related to Pinnacle West's gain on the sale of BCE.

Interest charges, net of allowance for borrowed funds and equity funds used during construction. Interest charges, net of allowance for funds used during construction, were $17 million higher for the three months ended March 31, 2024, compared to the prior-year period, primarily due to higher debt balances and higher interest rates in the current period and lower allowance for equity funds.

Income taxes. Income taxes were $3 million higher for the three months ended March 31, 2024, compared with the prior-year period primarily due to higher pre-tax income.

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 March 31, 2024, APS's common equity ratio, as defined, was 49%. Its total shareholder equity was approximately $7.3 billion and total capitalization was approximately $14.7 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $5.9 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 financings and equity infusions from Pinnacle West.

On December 15, 2022, the ACC issued a financing order reaffirming the previous 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) and approving APS's application filed April 6, 2022 requesting to 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. On April 19, 2024, APS submitted an application to the ACC requesting to increase the long-term debt limit from $8.0 billion to $9.5 billion. APS cannot predict the outcome of this matter.

APS is currently authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking ACC approval. On October 27, 2023, APS sought approval from the ACC to receive from Pinnacle West in 2024 up to an additional $500 million in equity infusions above the authorized limit of $150 million, and on January 9, 2024, the ACC approved the increased equity infusion limit for 2024. On April 19, 2024, APS submitted an application to the ACC requesting to increase Pinnacle West's permitted yearly equity infusions to equal up to 2.5% of Pinnacle West's consolidated assets each calendar year on a three-year rolling average basis. APS cannot predict the outcome of this matter.

Pinnacle West and APS maintain committed revolving credit facilities that enhance liquidity and provide credit support for accessing commercial paper markets. These credit facilities mature in 2028. See Note 3.

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

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Net Change
Net cash flow provided by operating activities	$ 347	$ 211	$ 136
Net cash flow used for investing activities	(424)	(453)	29
Net cash flow provided by financing activities	82	244	(162)
Net change in cash and cash equivalents	$ 5	$ 2	$ 3

Arizona Public Service Company

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Net Change
Net cash flow provided by operating activities	$ 366	$ 240	$ 126
Net cash flow used for investing activities	(462)	(427)	(35)
Net cash flow provided by financing activities	101	190	(89)
Net change in cash and cash equivalents	$ 5	$ 3	$ 2

Operating Cash Flows

Three-month period ended March 31, 2024, compared with three-month period ended March 31, 2023. Pinnacle West's consolidated net cash provided by operating activities was $347 million in 2024, compared to $211 million in 2023, an increase of $136 million in net cash provided, primarily due to $183 million lower fuel and purchased power costs, $65 million lower payments for operations and maintenance costs and $64 million higher cash receipts from electric revenues, partially offset by $120 million lower customer advances for construction, $22 million higher interest payments, $21 million higher income taxes and $13 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 110% funded as of January 1, 2024, and 112% as of January 1, 2023. 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 2024. 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 2024, 2025 or 2026. Regarding contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2024 and do not expect to make any contributions in 2024, 2025 or 2026. 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 102% funded as of December 31, 2023, and our postretirement benefit plans were 162% funded, as measured for GAAP purposes at December 31, 2023. See Note 5 for additional details.

Investing Cash Flows

Three-month period ended March 31, 2024, compared with three-month period ended March 31, 2023. Pinnacle West's consolidated net cash used for investing activities was $424 million in 2024, compared to $453 million in 2023, a decrease of $29 million primarily related to proceeds from the BCE Sale and lower BCE investment activity, partially offset by increased capital expenditures. The difference between APS's and Pinnacle West's net cash used for investing activities primarily relates to the BCE Sale. See Note 14 for additional details.

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

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2024	**2025**	**2026**
APS			
Generation:			
Clean:			
Nuclear Generation	$ 130	$ 130	$ 140
Renewables and Energy Storage Systems (“ESS”) (a)	175	305	280
Other Generation (b)	455	320	235
Distribution	565	550	590
Transmission	340	415	420
Other (c)	285	280	385
Total APS	$ 1,950	$ 2,000	$ 2,050

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

The table above does not include capital expenditures related to PNW Power 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, such as our current modernization project at our Sundance gas plant. 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

Three-month period ended March 31, 2024, compared with three-month period ended March 31, 2023. Pinnacle West’s consolidated net cash provided by financing activities was $82 million in 2024, compared to $244 million in 2023, a decrease of $162 million in net cash provided primarily due to $185 million in lower issuance of long-term debt, partially offset by a net increase in short-term borrowings of $27 million.

APS's consolidated net cash provided by financing activities was $101 million in 2024, compared to $190 million in 2023, a decrease of $89 million in net cash provided primarily due to $150 million equity infusion in prior year, partially offset by a net increase in short-term borrowings of $63 million.

Significant Financing Activities. On April 17, 2024, the Pinnacle West Board of Directors declared a dividend of $0.88 per share of common stock, payable on June 3, 2024, to shareholders of record on May 1, 2024.

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.

Equity Forward Sale Agreements. On February 28, 2024, Pinnacle West entered into various equity forward sale agreements (the "Equity Forward Sale Agreements"), which, at the option of Pinnacle West, may be settled in shares of Pinnacle West common stock with physical or net settlement or with cash settlement. At March 31, 2024, Pinnacle West could have settled the Equity Forward Sale Agreements with physical delivery of 11,240,601 shares of common stock to the counterparties in exchange for cash of $728 million. See Note 10 for more information on the Equity Forward Sale agreements.

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 March 31, 2024, the ratio was approximately 60% for Pinnacle West and 53% 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.

See Note 3 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of April 25, 2024, 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. On March 7, 2024, S&P affirmed the ratings and revised the Company’s and APS’s outlooks from negative to stable. On March 20, 2024, Moody’s downgraded both the Company’s and APS’s credit ratings by a notch and revised their outlooks from negative to stable. On March 26, 2024, Fitch affirmed APS’s ratings and downgraded the Company’s ratings by a notch. Fitch revised the outlook for both the Company and APS from negative to stable. 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	Baa2	BBB+	BBB
Senior unsecured	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F3
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	Baa1	BBB+	BBB+
Senior unsecured	Baa1	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable

The ratings of securities of Pinnacle West and APS as reported in our 2023 Form 10-K, are shown below:

	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 March 31, 2024. 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. Purchase obligations include capital expenditures and other obligations. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Notes 4 and 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.

- APS must reimburse certain coal providers for final and contemporaneous coal mine reclamation. See Note 8.

- The Equity Forward Sale Agreements, which may be settled by Pinnacle West with common stock or cash. Pinnacle West has classified the agreements as an equity transaction in accordance with GAAP. See Note 10.

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 2023 Form 10-K. See “Critical Accounting Policies” in Item 7 of the 2023 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 trust, other special use funds (see Notes 11 and 12), and benefit plan assets. The nuclear decommissioning trust, 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, coal reclamation, 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):

	Three Months Ended March 31,	
	2024	2023
Mark-to-market of net positions at beginning of period	$ (120)	$ 96
Increase in regulatory asset	(35)	(155)
Mark-to-market of net positions at end of period	$ (155)	$ (59)

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) at March 31, 2024, 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 2023 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2024	2025	2026	2027	2028	Total Fair Value
Observable prices provided by other external sources	$ (93)	$ (42)	$ (4)	$ —	$ —	$ (139)
Prices based on unobservable inputs	(12)	(2)	(2)	—	—	(16)
Total by maturity	$ (105)	$ (44)	$ (6)	$ —	$ —	$ (155)

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):

	March 31, 2024 Gain (Loss)		December 31, 2023 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	$ 10	$ (10)	$ 9	$ (9)
Natural gas	54	(54)	55	(55)
Total	$ 64	$ (64)	$ 64	$ (64)

(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 March 31, 2024. 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 March 31, 2024. 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 March 31, 2024, 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 2023 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 2023 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 2023 Form 10-K are not the only risks facing Pinnacle West and APS. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect the business, financial condition, cash flows and/or operating results of Pinnacle West and APS.

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Trading Plans

During the fiscal quarter ended March 31, 2024, 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.”

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ITEM 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
10.1[ab]	Pinnacle West APS	Summary of 2024 Variable Incentive Plan and Officer Variable Incentive Plan
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

*Furnished herewith as an Exhibit.
[a] Management contract or compensatory plan or arrangement

[b] Additional agreements, substantially identical in all material respects to this exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this 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
10.2	Pinnacle West	Forward Sale Agreement, dated February 28, 2024, between Pinnacle West and Wells Fargo Bank, National Association	10.1 to Pinnacle West February 28, 2024 Form 8-K File No. 1-8962	3/4/2024
10.3	Pinnacle West	Additional Forward Sale Agreement, dated February 28, 2024, between Pinnacle West and Wells Fargo Bank, National Association	10.2 to Pinnacle West February 28, 2024 Form 8-K File No. 1-8962	3/4/2024

(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.

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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: May 2, 2024

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: May 2, 2024

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